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Guidance for Lowest Achievable Emission Rates from 18 Major Stationary Sources of Particulate, Nitrogen Oxides, Sulfur Dioxide, or Volatile Organic Compounds

PEDCo-Environmental, Inc., Cincinnati, OH

Prepared for

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Office of Air Quality
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Research Triangle Park NC 27711

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16. ABSTRACT

This document provides guidance to the States for determining lowest achievable emission rates (LAER) for 18 major stationary sources of particulate, nitrogen oxides, sulfur dioxide, or volatile organic compounds. The source categories addressed are stationary gas turbines, kraft pulp mills, steel and iron foundries, petroleum refineries (three sources), fabric coating, industrial boilers, primary aluminum plants, bulk gasoline terminals, flat wood coating, gasoline and crude oil storage, graphic arts, and the coating of automobiles and light trucks, metal furniture and large appliances, cans, metal coils, and paper.

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U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air, Noise, and Radiation
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Project Officers for the Environmental Protection Agency were Messrs. John H. Haines and Gary D. McCutchen. The authors appreciate the contributions made by the EPA project officers and their associates.

SECTION 1

INTRODUCTION AND GENERAL DISCUSSION

1.1 INTRODUCTION

The Clean Air Act as amended in 1977 (CAAA 1977) contains three technology-based limitations affecting the location and construction of new or modified air pollution sources: (1) New Source Performance Standards (NSPS); (2) Best Available Control Technology (BACT); and (3) Lowest Achievable Emission Rate (LAER). Although NSPS and BACT are relatively familiar concepts that have been incorporated into statutes, regulations, and implementation plans, LAER is relatively new. The 1977 amendments established LAER as a statutory requirement, and EPA's Emission Offset Interpretative Ruling incorporated LAER as a regulatory demand in the preconstruction review of major stationary sources[1] which would contribute to a violation of an NAAQS. Additionally, the CAAA 1977 (§178) requires that the Administrator issue guidance documents for the purpose of assisting states in implementing the requirements of §129 and §173 pertaining to lowest achievable emission rate.

The purpose of this document is to provide technical assistance and guidance to those who must prepare and submit applications for proposed construction or modification of sources and facilities* and to those who must approve or deny such applications.

---

* Throughout this document the use of certain terms--major new source, facility, major modification, potential emissions, allowable emissions, NSPS, BACT, LAER--is intended to reflect the meanings imparted to those terms by the CAAA 1977.

The following sections deal with the interrelationships of the new source requirements embodied in the CAAA 1977; the legislative basis of LAER (including the factors that must be considered in determining LAER); some of the limitations and constraints involved in LAER determination; and, finally, the scope, intent, applicability, use, and limitations of the source-specific guidance in Section 3.

1.2 RELATIONSHIP OF NSPS, BACT, AND LAER

Because LAER is a relatively new requirement, it should be considered in relation to the other requirements applicable to new or modified major sources or facilities, that is, to NSPS and BACT.

The NSPS are applicable wherever a new source intends to locate (or in the case of a modified source--is located). They are limited to the specific sources and facilities that are the subject of a Federal promulgation (Title 40, Chapter I, Subchapter C, Part 60 CFR--Statutory authority, §111). An NSPS generally embodies specific emission limitations and may include operational and performance standards. The statute directs that the "standard of performance" shall be the best technological system of continuous emission reduction adequately demonstrated, considering cost, energy requirements, and other effects, such as socioeconomic impacts.

The BACT requirement is to be applied to new and modified sources subject to Prevention of Significant Deterioration (PSD) review and is required for each pollutant subject to regulation under the Act. The BACT review is relevant to major new or modified stationary sources or facilities.[2,3] The BACT and NSPS definitions are similar in that BACT must be technically achievable and must also reflect consideration of cost, energy requirements, and other possible impacts. The BACT requirement however is to be applied on a case-by-case basis and is also to consider any alternatives (production, process modification, control methods, systems, and techniques) that either singly or in combination could lead to further reduction in emissions if applied. Further, BACT is to be at least as stringent as any applicable NSPS or National Emission Standards for Hazardous Air Pollutants (NESHAPS). In a given case, therefore, the imposition of BACT limitations may be more stringent than NSPS or NESHAPS.

The LAER requirements are imposed in the review process on a proposed major new source or proposed major modification in a nonattainment area.[4-6] As applied to a modification, LAER means the lowest achievable emission rate for the new or modified facilities within the source.

Section II.A.7 of the proposed Emission Offset Interpretive Ruling[1] defines LAER as follows:

> "Lowest achievable emission rate" means for any source, that rate of emissions based on the following, whichever is more stringent:
>
> (i) the most stringent emission limitation which is contained in the implementation plan of any State for such class or category of source, unless the owner or operator of the proposed source demonstrates that such limitations are not achievable, or
>
> (ii) the most stringent emission limitation which is achieved in practice by such class or category of source.
>
> This term, applied to a modification, means the LAER for the new or modified facilities within the source. In no event shall the application of this term permit a proposed new or modified source to emit any pollutant in excess of the amount allowable under applicable new source standards of performance.

Although transfer of technology had only a minor role in the determination of LAER in this document, such decisions were guided by a pertinent discussion in EPA's proposed Emission Offset Interpretive Ruling.[1] This discussion ("Technology transfer in determining LAER," p. 3208) states:

> It has been EPA's interpretation that in determining the lowest achievable emission rate (LAER), the reviewing authority may consider transfer of technology from one source type to another where such technology is applicable. Although Congress changed the definition of LAER, EPA continues to believe that technology transfer may be considered in determining LAER. Congress intended to require new

> sources in nonattainment areas to apply the "maximum feasible pollution control," even if this involves "technology-forcing." Therefore, the Agency does not feel that the phrase "achieved in practice by such class or category of source" [under Section 171(3)] prohibits technology transfers from other types of sources. If pollution-control technology can feasibly be transferred from one type of source to another, then for purposes of determining LAER, EPA will consider both types of source to be in the same "class or category of source."

Of course, technology transfer need not be considered in determining LAER if it is not feasible for the specific application under consideration. Further, NSPS, BACT, and LAER all must be achievable before they are applied. The LAER provisions are generally more stringent than BACT, and BACT may be more stringent than NSPS. Neither BACT nor LAER can be less stringent than an applicable NSPS for the specific source or facility and the specific pollutant emitted.

1.3 LEGISLATIVE BASIS

Insight as to Congressional intent in adopting the LAER requirement and guidance to be followed in developing LAER limits are found in the Congressional Record (House, August 3, 1977, p. H 8551). The following quotation is from conference agreements between House and Senate.

> The House definition of "lowest achievable emission rate" is adopted for purposes of this section. In determining whether an emission rate is achievable, cost will have to be taken into account, but cost factors in the nonattainment content will have somewhat less weight than in determining new source performance standards under Section 111. Of course, health considerations are of prime importance. Facilities seeking to locate or expand in areas not meeting air quality health standards should be required to use the best control technology and processes available. The definition is intended to describe the lowest rate which is actually, not theoretically, possible. If the cost of a given control strategy is so great that a new major new source could not be built or operated, then such a control would not be achievable and could not be required by the Administrator.

These citations show clearly that LAER is intended to require more than add-on control devices. It calls for the consideration, selection, and application of alternative production procedures, modifications of unit processes, and control techniques in a combination that results in minimal pollutant release. In so doing, it establishes environmental concern as a prominent consideration in the early stages of planning of new and modified sources.

1.4 LAER GUIDANCE DOCUMENTS

1.4.1 Purpose

The CAAA 1977 calls for the issuance of guidance documents to assist the state in implementing Part D, Title 1, of the Act as it pertains to application of the lowest achievable emission rate to major new or modified stationary sources (§178). In satisfying this requirement, EPA intends to provide guidance in the form of reference material that is useful to engineers in industry and in state or local agencies, to those who prepare and those who review permit applications, to those regulated by the LAER requirement, and to those who implement that requirement.

1.4.2 Scope and Limitations

The user must recognize that the guidelines presented herein are limited as to scope and subject. This document pertains to selected major stationary sources, to certain emitting facilities within those sources, and to specific emissions from those sources or facilities. In the section on primary aluminum reduction plants, for example, the LAER guidance addresses only sulfur dioxide emissions from anode bake ovens and reduction cell facilities. It does not address LAER for grinding and mixing of materials, casting and tapping of metal or other emission points. Nor does it address other emissions (such as hydrocarbons, fluorides, and particulates) from the anode bake and reduction cell operations.

It is important to emphasize that the LAER criteria apply to all proposed major new or modified sources. The fact that no guidance document has been issued for a source-facility emission grouping does not relieve the appropriate authority from the obligation to apply LAER criteria in the permit review process; nor does it relieve the applicant from seeking to attain the lowest achievable emission rate.

The LAER requirement, like BACT and NSPS, is considered to be evolutionary and subject to change. Achievable levels of air pollution control will improve with technological advances. As new and improved technologies or processes are conceived, demonstrated, and practiced, they will be recognized and used. Today's state of the art will be replaced by that of tomorrow.

Finally, the technical information and guidance presented in this report are not intended to apply to all situations and specific conditions of the industrial processes and pollutants described here. This is termed a guidance document because it provides useful reference materials, but it should serve only as a starting point in a LAER investigative review.

In preparing these initial LAER guidelines, the time constraints specified in the CAAA 1977 and the need to allocate technical and professional resources within that time frame limited the scope and detail of the document. These time and manpower constraints dictated the following limitations on preparation of the guidance documents:

- No visits were made to sources or facilities to confirm technology and/or performance.
- The technical data base was drawn from telephone or written communication with equipment vendors, facility owners, governmental control agencies, and other groups, coupled with limited perusal of published literature.
- A cut-off date was established for data acquisition to provide sufficient time to catalog and analyze the information before preparing the document.
- A "current as of" date was fixed for review of regulations set forth in the State Implementation Plans (SIP), which undergo frequent revision.

Acquisition of technical information and SIP limitations through query by telephone or mail is subject to the celerity and generosity of the respondent.

Although every effort was made to maximize the quality of the data, the need to impose deadlines on data acquisition may have caused the exclusion of certain appropriate and relevant information.

REFERENCES

1. Appendix S--Emission Offset Interpretive Ruling Federal Register, Vol. 44, No. 11, January 16, 1979. p. 3282. (Although this was designated in the Federal Register as a final rule, the Administrator did invite comment on certain portions of the Ruling, indicating the possibility of change).

2. Title 40, part 51 of the Code of Federal Regulations, §51.24(b), (1) and (2), FR Vol. 43, No. 118, June 18, 1978, p. 26382 and as specified in §169(1), CAAA 1977.

3. Reference 2. §51.24(b)(17) p. 26383.

4. Reference 1. (II)(A) Definitions. (4) and (5) p. 3282.

5. Reference 1. (II)(A) Definitions. (6). p. 3282.

6. Reference 1. (IV, Condition 1). p. 3284 and footnote 2, p. 3283.

SECTION 2

METHODOLOGY: APPROACH AND PROCEDURES

2.1 INTRODUCTION

The CAAA 1977 defines LAER as the more stringent of two emission limitations for a class or category of source--that contained in the implementation plan of any state or that achieved in practice. The Act further requires that LAER be at least as stringent as an applicable NSPS limitation. Thus, the Act gives clear direction as to the major considerations in determining LAER. The methodology, approach, and procedures utilized were geared to discovering, for each source/facility/pollutant grouping, the most stringent emission limitation embodied in a State Implementation Plan (SIP), achieved in practice (AIP), or required by an applicable New Source Performance Standard (NSPS). Figure 2-1, LAER Determination Decision Tree, illustrates the approach and procedures used.

2.2 STATE IMPLEMENTATION PLAN (SIP) LIMITATIONS

The first step in the review of SIP limitations was to acquire an up-to-date file of current air pollution control regulations of the major state and local air pollution control agencies. The acquisition and verification procedures were as follows:

1. Letters were mailed to all state agencies and the most significant city, county, and regional agencies within each state. This letter advised the agency of the purpose of the LAER study and requested that the agency send, as soon as possible, a complete and current copy of its air pollution control laws and regulations.

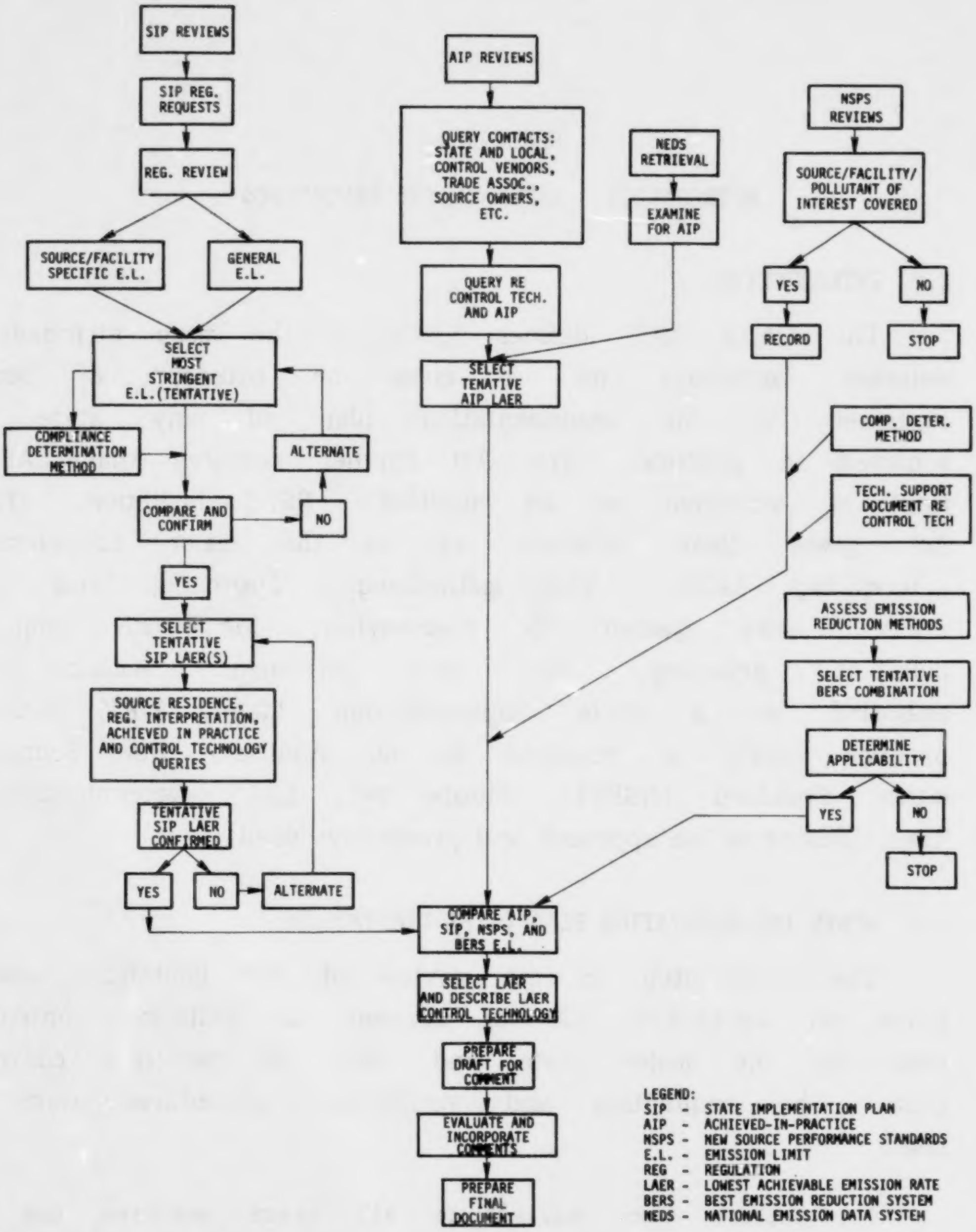

SIP REVIEWS
SIP REG. REQUESTS
REG. REVIEW
SOURCE/FACILITY SPECIFIC E.L.
GENERAL E.L.
SELECT MOST STRINGENT E.L. (TENTATIVE)
COMPLIANCE DETERMINATION METHOD
ALTERNATE
COMPARE AND CONFIRM
NO
YES
SELECT TENTATIVE SIP LAER(S)
SOURCE RESIDENCE, REG. INTERPRETATION, ACHIEVED IN PRACTICE AND CONTROL TECHNOLOGY QUERIES
TENTATIVE SIP LAER CONFIRMED
YES
NO
ALTERNATE
AIP REVIEWS
QUERY CONTACTS: STATE AND LOCAL, CONTROL VENDORS, TRADE ASSOC., SOURCE OWNERS, ETC.
NEDS RETRIEVAL
EXAMINE FOR AIP
QUERY RE CONTROL TECH. AND AIP
SELECT TENATIVE AIP LAER
NSPS REVIEWS
SOURCE/FACILITY/ POLLUTANT OF INTEREST COVERED
YES
NO
RECORD
STOP
COMP. DETER. METHOD
TECH. SUPPORT DOCUMENT RE CONTROL TECH
ASSESS EMISSION REDUCTION METHODS
SELECT TENTATIVE BERS COMBINATION
DETERMINE APPLICABILITY
YES
NO
STOP
COMPARE AIP, SIP, NSPS, AND BERS E.L.
SELECT LAER AND DESCRIBE LAER CONTROL TECHNOLOGY
PREPARE DRAFT FOR COMMENT
EVALUATE AND INCORPORATE COMMENTS
PREPARE FINAL DOCUMENT
LEGEND:
SIP - STATE IMPLEMENTATION PLAN
AIP - ACHIEVED-IN-PRACTICE
NSPS - NEW SOURCE PERFORMANCE STANDARDS
E.L. - EMISSION LIMIT
REG - REGULATION
LAER - LOWEST ACHIEVABLE EMISSION RATE
BERS - BEST EMISSION REDUCTION SYSTEM
NEDS - NATIONAL EMISSION DATA SYSTEM

Figure 2-1. LAER Determination "Decision Tree"

2. Approximately 2 weeks after the letters were sent, follow-up calls were made to jurisdictions that had not yet responded. The agency was again advised of the study purpose and requested to send a copy of current regulations.

3. Two cross-checks were made to verify that the state regulations provided were, in fact, the most current: the regulations given in the Environmental Reporter - State Air Laws, published by the Bureau of National Affairs, Inc., were compared with those sent by the states; the PEDCo files of state and local air pollution regulations, last updated in June 1976, were also examined.

Each response, as received, was dated and filed. An accounting of those jurisdictions not responding was maintained. Final tabulations indicated that the files contained current regulations for all states and for 54 city, county, and local jurisdictions. Generally, all regulations were current as of January 31, 1978.

In review of the regulations of each jurisdiction to ascertain the lowest emission limitation required in an SIP, the regulations were grouped into sets and subsets:

General Fuel Burning Regulations

- Particulate
- Sulfur Dioxide
- Oxides of Nitrogen

General Manufacturing Process Regulations

- Particulate
- Sulfur Dioxide
- Volatile Organic Compounds

Source-Specific Regulations

- By the specific major source types named in the guidance document

The regulations of each jurisdiction were reviewed and placed into the above groupings. Where a particular jurisdiction had no applicable regulation specific for a given source (e.g., Kraft Pulp Mills or Primary Aluminum Plants) an applicable general process regulation was cited. Each category was then examined to ascertain the most stringent SIP emission limitation. The limitations were viewed in conjunction with the specified compliance determination method (source test or other) because the two parameters--emission limitation and compliance determination method--together determine the relative degree of stringency of a limitation.

This process served to identify the most stringent SIP limitation and the responsible jurisdiction. The final steps were to determine whether a source is resident in the jurisdiction (or whether the regulation was designed to preclude entrance of such source), to resolve any questions involving interpretation of a regulation, and to acquire information regarding sources that had attained emission levels within the limitation.

2.3 ACHIEVED-IN-PRACTICE (AIP) LIMITATIONS

Three methods were used to obtain information regarding the lowest emission rate achieved in practice and the attendant control technology: queries were made to state and local control agencies, control equipment vendors, trade associations, source owners, and other; published literature was reviewed; and a limited "quick look" retrieval was obtained from the National Emissions Data System (NEDS). This retrieval covered the entire nation and listed for each pollutant/facility/source grouping of interest the source and location, source classification code, control device used, and emission reduction achieved. To reduce the volume of this listing the retrieval logic incorporated a control efficiency cut-off for each source-facility so that only those attaining a control efficiency greater than the specified cut-off value were listed. Information gleaned from the several methods was then examined to determine the lowest emission rate achieved in practice.

2.4 NEW SOURCE PERFORMANCE STANDARDS (NSPS) LIMITATIONS

EPA regulations adopted under statutory authority of Section 111, CAAA 1977, and promulgated under Title 40, Chapter I, Subchapter C Part 60 CFR are known as New Source Performance Standards (NSPS). Such standards are required by the Act to reflect the degree of emission limitation achievable by application of the best system of emission reduction that has been adequately demonstrated. NSPS have been promulgated for some of the sources addressed in this document. The NSPS citation in the Code of Federal Regulations (CFR) and the companion LAER guidance category (subsection of Section 3) are listed below.

	LAER CATEGORY		NSPS - 60 CFR SUBPART (AFFECTED FACILITY)
3.1	Stationary Gas Turbines (utility power plants - oxides of nitrogen, sulfur dioxide)	GG	Stationary Gas Turbines (>1000 Hp - oxides of nitrogen, sulfur dioxide) - proposed only - Oct. 1977
3.2	Kraft Pulp Mills (lime kilns - particulate; recovery furnaces - sulfur dioxide; and power boilers - particulate)	BB	Recovery furnaces (particulate), Smelt dissolving tanks (particulate), Lime kilns [particulate, total reduced sulfur (TRS) limited to 5 ppmv for seven facilities].
3.3	Electric Arc Furnaces (steel and gray iron foundries - particulate)	Z	Ferroalloy Production Facilities* (electric submerged arc furnaces - particulate).
3.3	Electric Arc Furnaces (steel and gray iron foundries - particulate)	AA	Steel Plants* (electric arc furnaces - particulates)
3.4	Petroleum Refiners (catalytic crackers - sulfur dioxide)	J	Petroleum Refineries (catalytic cracker - particulate, CO)
3.6	Industrial Boilers (particulate, sulfur dioxide, oxides of nitrogen)	D	Fossil-Fuel-Fired Steam Generators (>250 million Btu/h - particulate, sulfur dioxide, oxides of nitrogen)
3.7	Primary Aluminum Reduction (reduction cells and anode bake oven - sulfur dioxide)	S	Primary Aluminum Reduction Plants (reduction cell potrooms and anode bake plant - fluorides)
3.10	Petroleum Liquids Storage (hydrocarbons)	K	Storage Vessels for Petroleum Liquids (>40,000 gal capacity - hydrocarbons)

* NSPS are planned specific to particulates from electric arc furnaces in steel and gray iron foundries.

The NSPS specifies an affected facility and the pollutants covered by the standard. The LAER guidance also pertains to specific facilities and pollutants. The two NSPS and LAER categories were examined for a match of source/facility/pollutant groupings. Where that match occurred, the NSPS emission limitation was recorded for comparison with the AIP- and SIP-derived LAER values.

2.5 LAER FINALIZATION

The tentative LAER limits from review of AIP and SIP were then compared and the more stringent of the two was selected. Where an NSPS was applicable, the AIP-SIP selection was compared with the NSPS limitation and again the more stringent was selected. Finally consideration was given to changes in raw material input, to production and process modifications, and to technology transfer in a combination that would represent a best system of emission reduction that could be applied to a given source/facility/pollutant set. A final LAER value was then selected, and the technology for achieving the emission limitation was described. Factors that could limit application of the technology were addressed.

The draft document was then organized in standard format of the EPA Office of Research and Development (ORD), subjected to editorial scrutiny, and offered to affected and interested parties for review and comment. The comment period was intended to allow for discovery and correction of any errors and to permit consideration of comments and other information that would enhance the clarity and technical accuracy of the document. Appropriate modifications based on these and internal review comments have been incorporated into the final document.

SECTION 3
LAER GUIDELINES

This Section consists of 18 subsections that deal with LAER for pollutants emitted from the facilities of certain major sources. Not all pollutants that may be emitted from a facility are covered, nor are all the facilities at a major source. The guidance pertains to a limited number of stationary sources, to selected facilities within those sources, and to specific emissions from those facilities. The format of each guidance consists of Process Description, Emissions, Control Measures, Emission Limits, and Determination of LAER.

This is a technical document, for guidance only, and it should not be construed as regulatory in nature. Its purpose is to provide technical information and reference materials for use as a starting point in making a LAER determination, not for rigidly prescribing LAER. The information presented is limited in scope and is not intended to apply to all situations and conditions that may be encountered in the review of permit applications. The guidances do not replace the individualized attention and consideration to be afforded an entity that seeks approval to install a new--or modify an existing--source. The review authority is encouraged to recognize the individuality of each permit application and the desirability of a case-by-case approach that ultimately leads to a LAER determination based on and specifically tailored to a given set of circumstances.

Caution should be exercised in utilizing this document because of the anticipated changes in the CAAA 1977 specified criteria upon which LAER determinations are to be made, i.e., State Implementation Plan (SIP) limits, achieved-in-practice

(AIP) levels, and New Source Performance Standards (NSPS). Changes in SIP-related limitations are imminent in response to CAAA 1977 requirements that SIP's be revised for areas where the National Ambient Air Quality Standards (NAAQS) have not been attained. Also, advances in control technology and in equipment performance can be expected to result in AIP levels lower than those reported here. Furthermore, an expanded list of sources are to be the subject of NSPS promulgation in the near future, and consideration is being given to revising some NSPS. Therefore, the user should verify that the SIP, AIP, and NSPS limits in this document are currently applicable and have not changed since document publication.

Finally, it is important to note that these guidelines apply to both new and modified facilities. With regard to modified or reconstructed facilities, the reviewer may give case-by-case consideration to any special economic or physical constraints that might limit the application of certain control techniques to a modification project, i.e., the level of control required for a process undergoing modification or reconstruction may not be as stringent as that required if the same process were a grass-roots construction project.

3.1 MAJOR SOURCE CATEGORY: STATIONARY GAS TURBINES/ELECTRIC UTILITIES--NITRIC OXIDE AND SULFUR DIOXIDE EMISSIONS

3.1.1 Process Description

A gas turbine is a rotary engine, of which a common example is the jet aircraft engine. Compressed air is rapidly expanded by the combustion of a fuel in a combustion chamber. The high velocity and high temperature gases rotate a turbine fan that drives a power-output shaft. Figure 3.1-1 presents a cutaway view of a stationary gas turbine.[1] Turbines range in size from less than 30 kW (40 hp) to over 75 MW (10^5 hp).[2] Manufacturers continue to increase turbine capacity, and turbines are often installed in groups, so that the combined power output from one location may exceed 1.12 GW (1.5×10^6 hp).[3] Over 90 percent of the horsepower sold in the U.S. goes to utilities and that margin continues to widen.[4]

Three basic types of gas turbines are used in the electric power industry: simple cycle, regenerative cycle, and combined cycle. A simple cycle gas turbine consists typically of one or more compressor stages, one or more combustion chambers where liquid or gaseous fuels are burned, and one or more turbines to drive the compressor and the load. These can be arranged in various configurations. Figure 3.1-2 is a block diagram of a typical simple cycle gas turbine.[5] The turbine is started with an electric motor, diesel engine, or other energy source to rotate the compressor that provides compressed air to the combustors. Fuel is then introduced into the combustors and burned to produce hot gases, which expand across the first set(s) of turbine blades, providing the driving force to continue rotating the compressor(s) mounted on the same shaft. The hot gases are further expanded across the power turbine blades that drive the electrical generators. The exhaust gases, containing pollutants, exit to the atmosphere at temperatures ranging from 430° to 600°C (800° to 1100°F).[6]

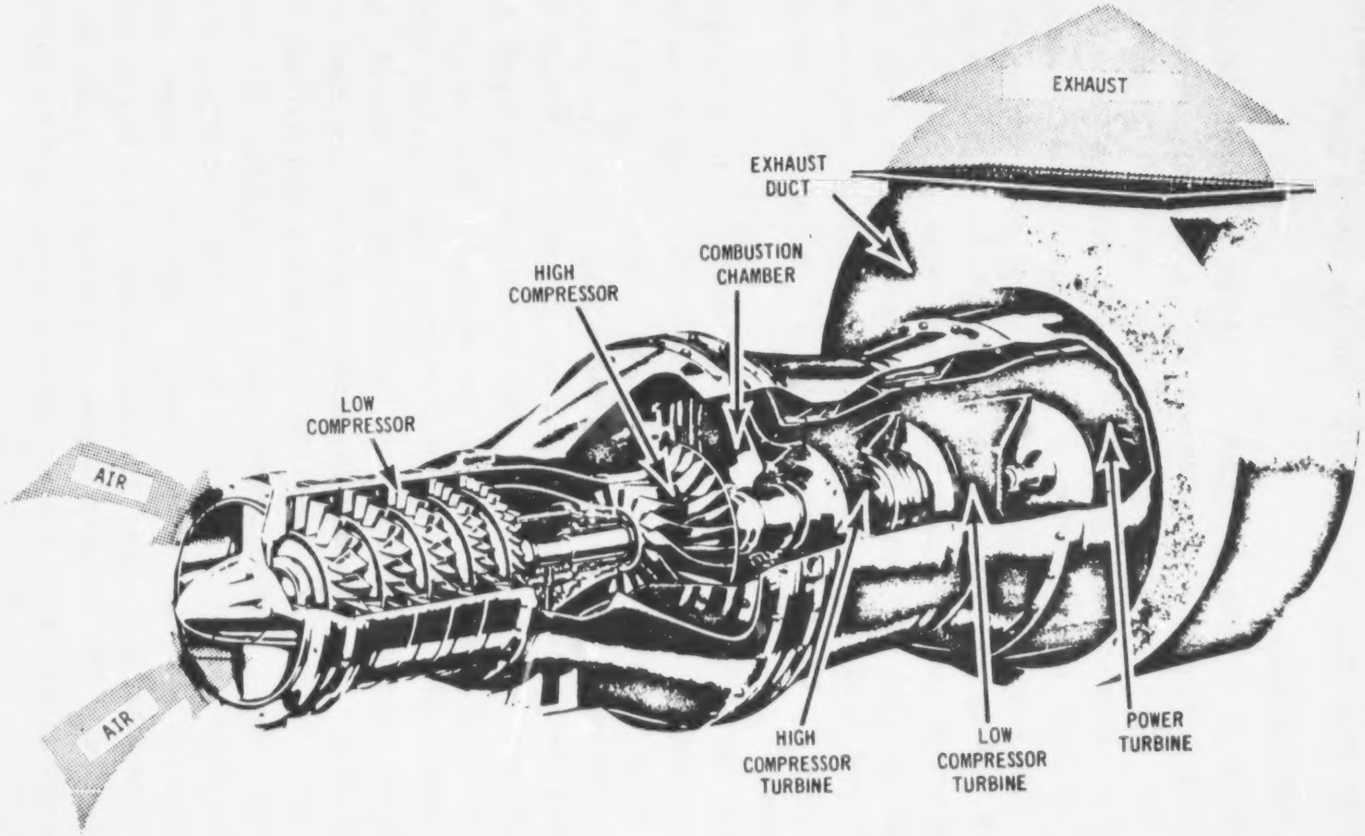

EXHAUST
EXHAUST DUCT
COMBUSTION CHAMBER
HIGH COMPRESSOR
LOW COMPRESSOR
AIR
AIR
HIGH COMPRESSOR TURBINE
LOW COMPRESSOR TURBINE
POWER TURBINE

Figure 3.1-1. Cutaway view of a typical stationary gas turbine.

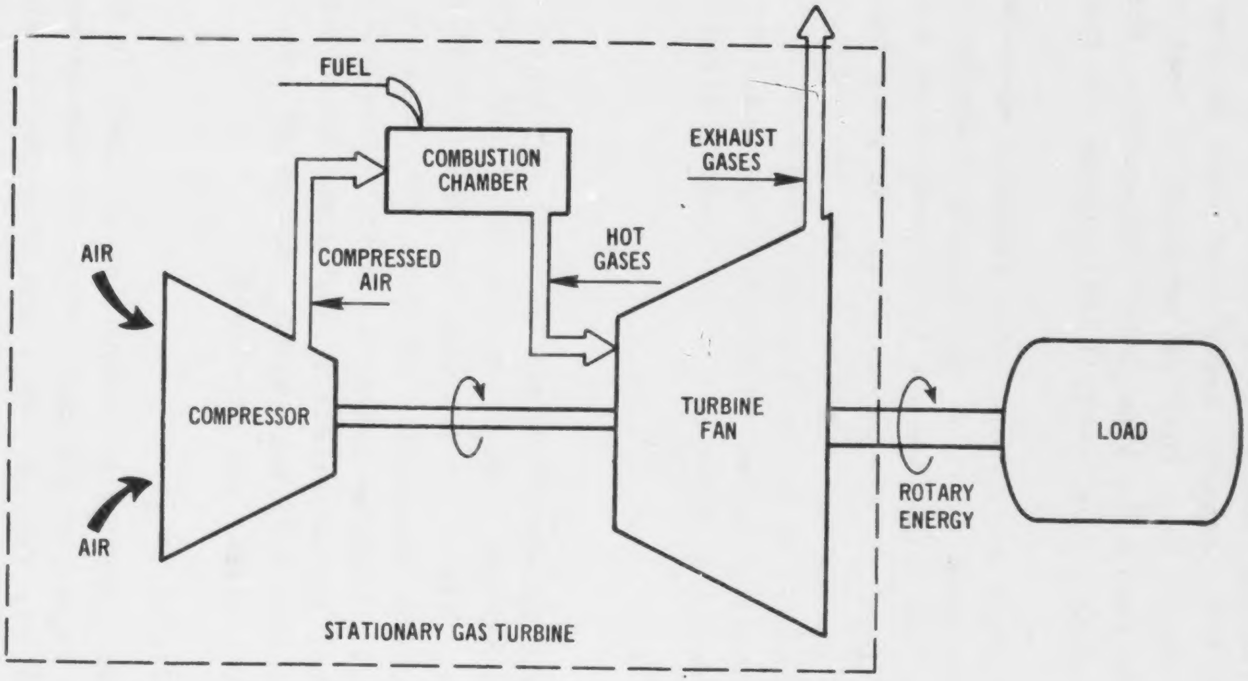

FUEL
COMBUSTION CHAMBER
EXHAUST GASES
AIR
COMPRESSED AIR
HOT GASES
COMPRESSOR
TURBINE FAN
LOAD
AIR
ROTARY ENERGY
STATIONARY GAS TURBINE

Figure 3.1-2. Typical simple cycle gas turbine.

The regenerative cycle gas turbine is essentially a simple cycle gas turbine with an added heat exchanger, as shown in Figure 3.1-3.[7] Thermal energy is recovered from the 430° to 600°C (800° to 1100°F) exhaust gases[6] and used to preheat the compressed air. Since less fuel is required to heat the compressed air to the design turbine inlet temperature, the regenerative cycle improves the overall efficiency of the simple cycle.

The combined cycle gas turbine also recovers waste heat from the turbine exhaust gases. It is essentially a simple cycle gas turbine with the hot gases vented to a waste heat boiler, as shown in Figure 3.1-4.[8] Steam generated by the waste heat boiler can be used to generate electricity with conventional steam turbines. Some waste heat boilers are designed to generate additional steam by the firing of conventional fuels in a firebox. Such systems are known as supplementary-fired combined cycle gas turbines.

3.1.2 Emissions

The pollutants generated by gas turbines are those common to all combustion processes: NO_x, HC, CO, SO_2, particulates, and visible emissions. Table 3.1-1 summarizes the typical pollutant emissions, which are dependent on such variables as turbine firing temperature, turbine pressure ratio, turbine load, combustor design, fuel characteristics, and atmospheric conditions. This section discusses only SO_2 and NO_x, for which lowest achievable emission rates (LAER) are developed.

3.1.2.1 Nitric Oxides (NO_x)--

Nitric oxides produced by combustion of fuels in stationary gas turbines are formed by the combination of nitrogen and oxygen in the combustion air (thermal NO_x) and from the reaction of the nitrogen in the fuel with the oxygen in the combustion air (organic NO_x). Formation mechanisms are complex, and detailed discussion is beyond the scope of this document.

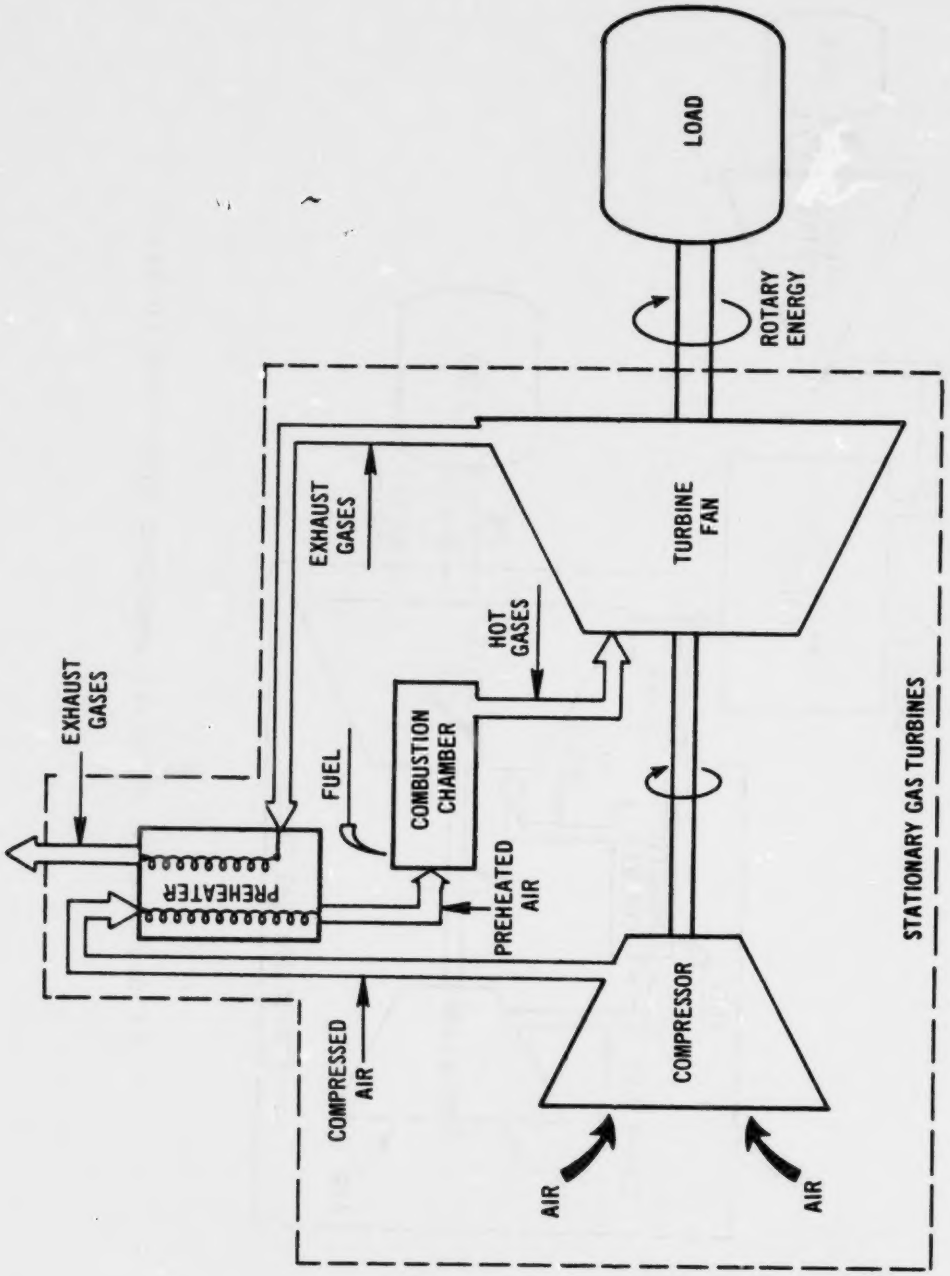

EXHAUST GASES
PREHEATER
FUEL
COMBUSTION CHAMBER
HOT GASES
EXHAUST GASES
TURBINE FAN
ROTARY ENERGY
LOAD
PREHEATED AIR
COMPRESSED AIR
COMPRESSOR
AIR
AIR
STATIONARY GAS TURBINES

Figure 3.1-3. Typical regenerative cyclone gas turbine.

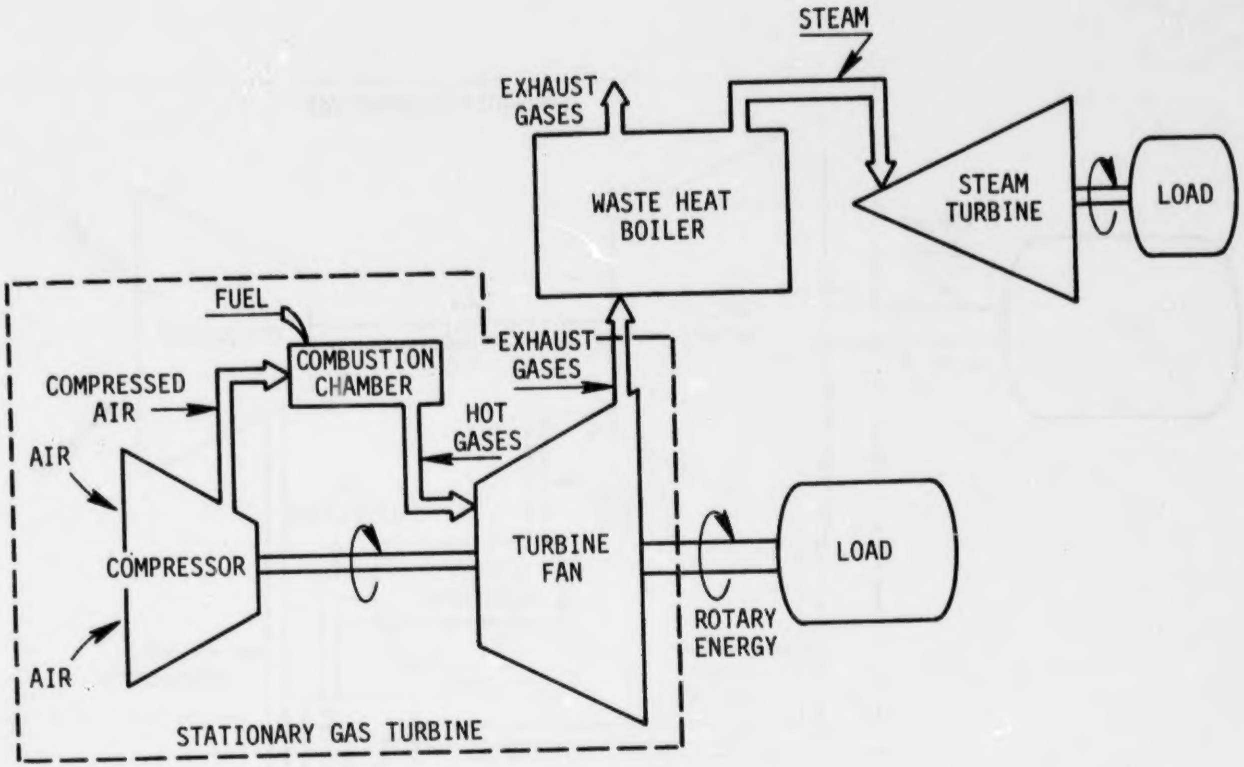

STEAM
EXHAUST GASES
WASTE HEAT BOILER
STEAM TURBINE
LOAD
FUEL
COMBUSTION CHAMBER
EXHAUST GASES
COMPRESSED AIR
HOT GASES
AIR
COMPRESSOR
TURBINE FAN
LOAD
AIR
ROTARY ENERGY
STATIONARY GAS TURBINE

Figure 3.1-4. Typical combined cycle gas turbine.

TABLE 3.1-1. UNCONTROLLED POLLUTANT EMISSIONS FROM TYPICAL STATIONARY GAS TURBINES[9]

Pollutant	Symbol	Uncontrolled emissions		
		g/kWh	$lb/10^3$ hp-h	ppmv @ 15% O_2
Carbon monoxide[a]	CO	0.13-16	0.2-26	2.3-160
Sulfur dioxide[b]	SO_2	5.35-7.75	8.75-13.5	NR
Nitric oxides[c]	NO_x	7.3-4.0	12-66	50-350
Hydro carbons[a]	HC	0.22-1.1	0.36-1.8	1-5 (as hexane)
Particulate[d]		NR	NR	0.002-0.1 gr/scf

[a] Highly dependent on combustion efficiency.

[b] S = sulfur content of fuel in weight percent.

[c] Highly dependent on combustion temperature, combustor design, fuel nitrogen, and other factors as discussed.

[d] Highly dependent on type of fuel and combustion efficiency.

NR = not reported.

Several major factors limit the formation of NO_x: the availability of O_2, the combustor residence time and temperature, the amount of moisture in the inlet air, and combustor pressure.[10,11,12] The quantity of NO_x emissions generated by gas turbines is limited by the residence time of the hot gases in the engine combustors and by the rapid quenching of these gases by dilution air. Therefore, very high combustion efficiencies (high temperature) can be attained without generating the very high equilibrium quantities of NO_x. Humidity in the inlet air will decrease NO_x formation by reducing the combustion flame temperature.[12]

Organic NO_x is formed during combustion by the chemical combination of the nitrogen atoms contained in the fuel molecule with oxygen in the air. The exact mechanism is not known.[13,14,15] Generally, organic NO_x is a problem only in burning of residual oils, blends, some crude oils, or heavy distillates that have high nitrogen contents.[15,16] Table 3.1-2 indicates the nitrogen content of various fuels.

NO_x emissions from gas turbines were measured and reported for over 50 source tests.[20] Uncontrolled NO_x emissions ranged from about 40 to 500 ppm at 15 percent O_2 for all fuels, and averaged 90 ppm for natural gas, 130 ppm for distillate fuel, and 190 ppm for jet-A type fuel. Table 3.1-3 gives the range and average of uncontrolled NO_x emissions from the sources that were tested which include combustor rigs (models) as well as full-scale turbines.

3.1.2.2 Sulfur Dioxide (SO_2)--

The formation of SO_2 in stationary turbine operations is strictly a function of the sulfur content of the fuel. Generally 100 percent of the sulfur is converted to SO_2. Table 3.1-2 shows the typical concentrations of sulfur in common fuels. Turbine operators generally use low-sulfur natural gas and light distillates,[21] although crudes and residuals can also be used.

TABLE 3.1-2. NITROGEN AND SULFUR CONTENTS OF COMMON FUELS

Fuel	Content, percent by weight	
	Nitrogen[a]	Sulfur[b]
Natural gas	nil	0-0.1
Distillate oil	<0.015	0.01-0.48
Crude oil	<0.2	0.06-3.0
Residual oil	<2.0	0.5-3.2

[a] References 15 and 16.

[b] References 17 and 18.

TABLE 3.1-3. NO_x EMISSIONS BY TYPE OF FUEL[20]

Fuel	Uncontrolled NO_x emissions, ppmv @ 15% O_2		
	Range	Average	Number of tests
Natural gas	40-150	90	18
Distillate fuel	50-240	130	30
Jet-A	40-500	190	9

The SO_2 concentration is calculated at 180 to 260 S ppm, depending upon the sulfur content (S) of the fuel and the exhaust gas rate. The sulfur content is expressed in weight percent. The mass rate emission factor is determined to be 0.02 S kg SO_2/kg fuel (0.02 S lb SO_2/lb fuel), where S is the sulfur content in percent by weight. This is approximately equivalent to 5.3 S to 7.7 S g SO_2/kWh (8.7 S to 13 S lb $SO_2/10^3$ hp-h).

3.1.3 Control Measures

3.1.3.1 NO_x Control--

Wet control techniques--Because formation of NO_x is extremely sensitive to flame temperature, injecting water or steam into the reaction zone will reduce production of NO_x.[22] In full-scale field operations reductions of up to 70 to 90 percent have been achieved at water-to-fuel (w/f) ratios of 1.0 and reductions of 50 to 70 percent have been observed at w/f ratios from 0.5 to 0.7, as shown in Figure 3.1-5.[23] Industry readily accepts this technique for control of NO_x.[24] One manufacturer guarantees an NO_x emission limit of 75 ppm at 15 percent stack gas oxygen.[25]

For distillate-fuel-fired turbines, one EPA test shows the highest reduction of 85 percent, from 315 ppm to 58 ppm NO_x (w/f ratio of 1.1).[26] Another EPA test showed the lowest concentration of about 26 ppm NO_x, inlet concentration 163 ppm, and 84 percent efficiency in the stack gas of a liquid-fuel-fired turbine at a water-to-fuel ratio of 1.1.[27] For natural-gas-fired turbines the highest reduction in one source test was from 110 ppm to 13 ppm NO_x (88 percent) at a w/f ratio of 1.0. This facility also yielded the least NO_x emissions (13 ppm) with wet controls.[28]

Water-to-fuel ratios above 1.0 do not decrease the formation of NO_x substantially. Water and steam injection have essentially the same effect on NO_x emissions. The overall gas turbine efficiency is reduced by about 1 percent at a w/f ratio of 1.0,

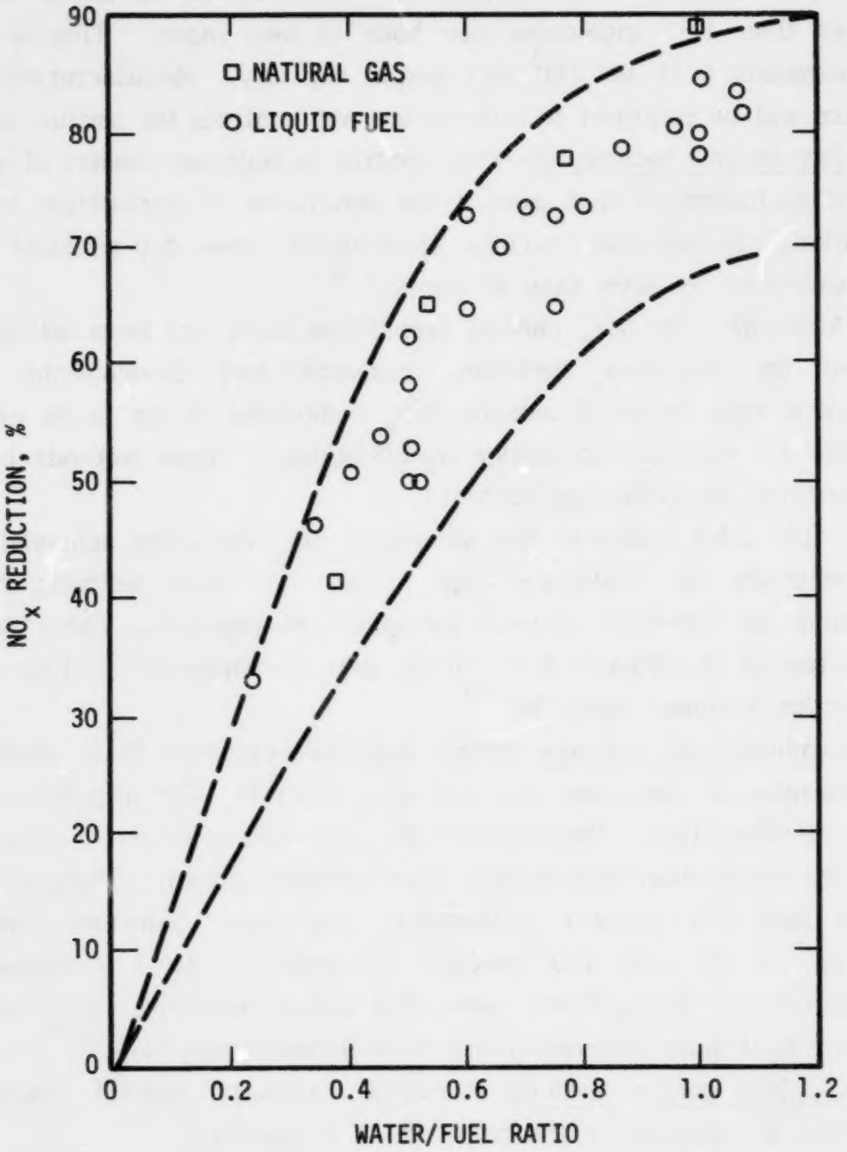


Figure 3.1-5. Effectiveness of water/steam injection in reducing NO_x emissions.[10]

corresponding to about a 5 percent increase in fuel consumption.[29]

This control technique is considered to be the best system of emission reduction to achieve NSP standards for NO_x on turbines with capacities greater than 10.7 gigajoules per hour of heat input. This is equivalent to approximately 0.75 MW (10^3 hp) output capacity. Manufacturers estimate that 3 years will be required to incorporate wet controls for smaller units.[30]

Dry control techniques--Dry control techniques consist of operational or design modifications that govern the conditions of combustion to reduce NO_x formation. In full-scale turbine applications, some dry methods have reduced NO_x emissions by more than 40 percent.[31]

Although dry NO_x control techniques have not been adequately demonstrated on full-scale turbines, research and development efforts with combustor rigs (models) indicate NO_x reductions of up to 94 percent may be possible by various combustion modifications. These methods have not been incorporated in production turbines.

Table 3.1-4 indicates the degree of NO_x reduction achieved with various dry methods on combustor rigs. Some of these methods have reduced emissions on full-scale engines by about 40 percent. These data represent the potential of efficient dry control methods which may not be developed for production turbines until 1982.[30]

Combined wet and dry control methods--Emission tests showed the best performance of combined wet and dry controls with a peaking gas turbine using distillate fuel. Uncontrolled NO_x was measured at 173 ppm at 15 percent O_2. By combustion modification (lean primary zone), emissions were reduced to 82 ppm (53 percent reduction). By water injection, emissions were reduced to 34 ppm (80 percent reduction). By a combination of lean combustion in the primary zone and water injection, NO_x emissions were reduced to 16 ppm, corresponding to 91 percent reduction.[32]

Catalytic control methods--Catalytic exhaust control consists of NO_x reduction by ammonia in the presence of a catalyst.

Laboratory tests have demonstrated reductions of up to 98 percent.[33] Because this technique has not been demonstrated on full-scale turbines,[30] it cannot be considered as a LAER control method.

TABLE 3.1-4. NO_x EMISSION REDUCTIONS BY DRY CONTROL TECHNIQUES ON EXPERIMENTAL COMBUSTOR RIGS[32]

Technique	NO_x reduction, %
Lean burn, fuel-air mixing in full-size combustor rig	12-44
Lean primary in half-size combustor rig	15-20
Exhaust gas recirculation, half-size combustor rig	30-38
Rig tests; premix, prevaporization, staged combustion, lean burn	35-61
Lean primary, reduced residence time in full-size combustor rig	40
Lean burn, premix, staged fuel and air; full-size rig	51-60
Vortex air blast rig	94

3.1.3.2 SO_2 Control--

Because SO_2 emissions from gas turbines are strictly a function of the fuel sulfur content (and essentially all sulfur is converted to SO_2), the only technique being used to control SO_2 emissions from gas turbines is use of low-sulfur fuels. Flue gas desulfurization (stack gas scrubbing) systems are economically unattractive compared to the cost of low-sulfur fuel because of the large gas volumes to be treated and the low SO_2 concentrations.

Sulfur content of distillate fuels used in gas turbines commonly ranges from 0.01 to 0.48 percent by weight; sulfur in crudes ranges from 0.06 to 3.0 percent, and in residual oils from 0.5 to 3.2 percent.[17,18] Some residual oils have much higher sulfur contents, but these are unusable in gas turbines. Sulfur content of natural gas may range from 0 to 0.1 percent.[17,18]

3.1.4 Emission Limits

3.1.4.1 NO_x Limits--

Although a few state and local control agencies apply regulations specifically to stationary gas turbines, most states apply general standards to gas turbines. The most stringent SIP limits on NO_x emissions applicable to gas turbines are 86 g NO_x/GJ (0.2 lb $NO_x/10^6$ Btu) input for gas-fired burners and 128 g/GJ (0.3 lb $NO_x/10^6$ Btu) for oil-fired burners.[34,35] These standards, approximately equivalent to 50 and 75 ppmv, respectively, are applied in eight states. Apparently the most stringent of all state regulations is that of San Diego County, California, which limits emissions to 75 ppmv and 42 ppmv at 15 percent oxygen when burning liquid and gaseous fuels, respectively.[36]

The New Source Performance Standards (NSPS) for stationary gas turbines are applicable to turbines whose peak load is equal to or greater than 10.7 GJ/h (10×10^6 Btu/h) of heat input. The emissions limit for NO_x is 75 ppm by volume at 15 percent oxygen and International Standard Organization (ISO) ambient atmospheric conditions. The standard also includes an adjustment factor for gas turbine efficiency and a fuel-bound nitrogen allowance. NO_x emissions would be limited according to the following equation:[37]

$$\text{STD} = (0.0075\ E) + F$$

STD = allowable NO_x emissions (percent by volume at 15 percent oxygen)

E = efficiency adjustment factor

$$= \frac{14.4\ \text{kJ/Wh}}{\text{Actual ISO heat rate}} \quad \text{or} \quad \frac{(13{,}600\ \text{Btu/kWh})}{\text{Actual ISO heat rate}}$$

F = Fuel-bound nitrogen allowance

Fuel-bound nitrogen (percent by weight)	F (NO_x, percent by volume)
$N \leq 0.015$	0
$0.015 < N \leq 0.1$	0.04 (N)
$0.1 < N \leq 0.25$	0.004 + 0.0067 (N-0.1)
$N > 0.25$	0.005

The NSPS would allow an additional 50 ppm NO_x attributable to fuel NO_x.

The most stringent of all NO_x regulations applicable to gas turbines appears to be the 42 ppm limit of San Diego County for gaseous fuels.

The lowest NO_x emission rate achieved in practice, based on available data, is 13 ppm [21 g NO_x/GJ (0.05 lb $NO_x/10^6$ Btu) input] by an 88 percent reduction using water injection.[28] An NO_x concentration of 16 ppm has been achieved by combined wet and dry control techniques with an efficiency of 91 percent.

3.1.4.2 SO_2 Limits--

State implementation plans limit the amount of sulfur in fuels to 0.3 to 2.6 percent by weight, with an average of 1.0 percent.[38] The most stringent 0.3 percent limit corresponds to about 130 g SO_2/GJ (0.3 lb $SO_2/10^6$ Btu) input.

New Source Performance Standards require SO_2 reduction to 150 ppm by volume, corrected to 15 percent oxygen, or a maximum fuel sulfur content of 0.8 percent by weight.[39] The 150 ppm limit corresponds to about 346 g SO_2/GJ (0.8 lb/10^6 Btu) input.

The most stringent current SO_2 regulation applicable to gas turbines appears to be an SIP limit of 0.3 percent sulfur content of the fuel, corresponding to 130 g SO_2/GJ (0.3 lb of $SO_2/10^6$ Btu) input or about 56 ppm by volume.

3.1.4.3 Most Stringent Limits--

The most stringent NO_x limit is the San Diego 42 ppm limit, and the most stringent SO_2 limit is the SIP and NSPS maximum of 0.3 weight percent sulfur content in liquid fuels and essentially zero for natural gas.

3.1.5 Determination of LAER

The recommended limitations are based on SIP's and on performance information available in early 1979. It is anticipated that several additional SIP regulations covering these sources will be promulgated and/or modified in 1979 and 1980 and that appreciable new performance data will become available in the near term. Conceivably, some SIP regulations may be more stringent than the LAER suggested herein. Furthermore, performance testing may show that more stringent limits than those suggested are feasible or it may show that the suggested limits are appropriate or that they are not achievable for some specific subcategories. In any case, the basis for determining LAER for many source categories is expected to change frequently. Since LAER is near the vanguard of control technology, a more detailed analysis is particularly necessary when addressing modified or reconstructed facilities subject to the provisions of Section 173 of the Clean Air Act. Emission limitations reasonable for new sources may in some instances be economically or technically unreasonable when applied to modified or reconstructed sources of the same type.

3.1.5.1 LAER for NO_x--

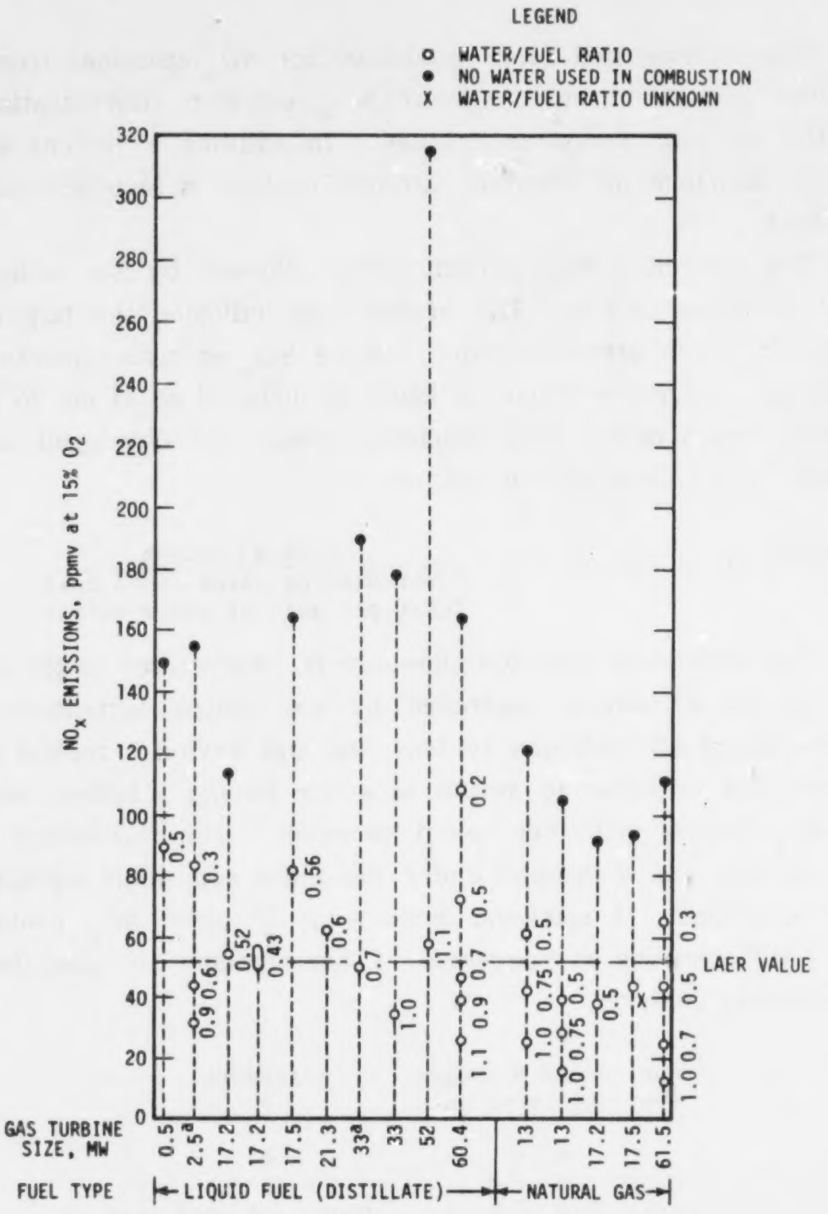
The recommended LAER guidelines for NO_x emissions from stationary gas turbines are based on the lower NO_x emission concentrations achieved in practice by wet control techniques. In addition a turbine efficiency factor and an allowance for the fuel nitrogen content is incorporated into the LAER guideline.

The controlled NO_x concentrations achieved by wet techniques are indicated in Figure 3.1-6. The broken line indicates the baseline LAER at 50 ppmv NO_x at 15 percent oxygen. Since NO_x emissions increase with turbine efficiency, a turbine efficiency factor is included so as not to penalize energy efficient operations. This efficiency factor was developed under the NSPS studies.[1] It is computed as follows,

$$\text{Efficiency factor, } E = \frac{14.4 \text{ kJ/watt-h}}{\text{lower heating value (LHV) heat input per unit of power output}}$$

The fuel-bound nitrogen allowance is incorporated in the LAER since fuel NO_x is not effectively controlled by wet control techniques. Hence, if a turbine firing low nitrogen content fuel and having a control efficiency of 90 percent was required to switch to a fuel having a higher nitrogen content, the NO_x control efficiency would decrease. The fuel-bound nitrogen allowance concept was developed under the NSPS and would equally apply for the LAER guideline. A maximum increase of 50 ppmv NO_x above the 50 ppmv NO_x LAER baseline is suggested. This allowance is computed according to the following method:

Fuel-Bound Nitrogen (percent by weight)	Allowance F
$N \leq$	0
$0.015 < N \leq 0.1$	0.04 (N)
$0.1 < N \leq 0.25$	0.004 + 0.0067 (N-0.1)
$N > 0.25$	0.005



[a] Tests made on model combustor rigs rather than in the field

Figure 3.1-6. Summary of NO_x emission data from gas turbines using wet control techniques.[40] (Taken from field or engine tests except where noted.)

Like the proposed NSPS, the measured NO_x emission rate is corrected to 15 percent oxygen and ISO conditions. ISO conditions are defined as standard ambient conditions of 1 atmosphere pressure, 60 percent relative humidity, and 288°K.

The recommended LAER guidelines for NO_x emissions are stated as the following:

$$NO_x = [0.0050 (E) + F]$$

where: NO_x = NO_x emission LAER at 15 percent O_2
E = Efficiency factor, above
F = Fuel-nitrogen allowance, above

3.1.5.2 LAER for SO_2--

The LAER for SO_2 is recommended to be the emission rate associated with firing liquid fuels containing a maximum of 0.3 percent by weight sulfur. This is approximately equivalent to 50 ppmv SO_2 or 130 g/GJ (0.3 lb/10^6 Btu) and is based on the most stringent SIP regulation. The LAER for gaseous fuels would be essentially no SO_2 emissions.

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3.2 MAJOR SOURCE CATEGORY: KRAFT PULP MILL LIME KILNS, POWER BOILERS (BARK AND COMBINATION) FOR PARTICULATE ONLY; RECOVERY FURNACE FOR SULFUR DIOXIDE ONLY

3.2.1 Process Descriptions

3.2.1.1 Kraft Pulp Mill--

The Kraft chemical wood pulping process involves the extraction of cellulose fibers, or "wood pulp," from the wood by dissolving and removing the lignin that binds the cellulose fibers together. The pulp is suitable for making paper, paperboard, and building materials. More than 80 percent of the chemical wood pulp made in the United States is produced by the Kraft method,[1] which can be used with almost any wood species, requires a relatively short time period to complete delignification, does not degrade the valuable cellulose and hemicelluloses in the wood as badly as other chemical pulping processes, and permits recovery of a high percentage of the cooking chemicals.[2]

Figure 3.2-1 is a flow sheet of typical Kraft pulp mill operations showing the recovery and recycling of the valuable sodium salts. Pulpwood logs are debarked and chipped (not shown), and the chips are fed into a continuous digester countercurrent to a fresh chemical stream (called white liquor) containing about 21 percent active chemicals, of which three quarters is sodium hydroxide and one quarter is sodium sulfide in water solution. The digester is held at 7.03 to 9.49 kg/cm^2 (100 to 135 psig) and 170° to 175°C (338° to 347°F).[3] Time required for the cooking cycle is from 1 hour for unbleached brown pulp to as much as 5 or 6 hours for pulps that are to be bleached.[3] The cooking process causes formation of malodorous sulfide gases, such as hydrogen sulfide, methyl mercaptan, and dimethyl sulfide. Venting of these gases gives a kraft mill its typical sour odor.

The contents of the digester exit through a "blow tank," where steam and noncondensibles are flashed-off, and cooked chips

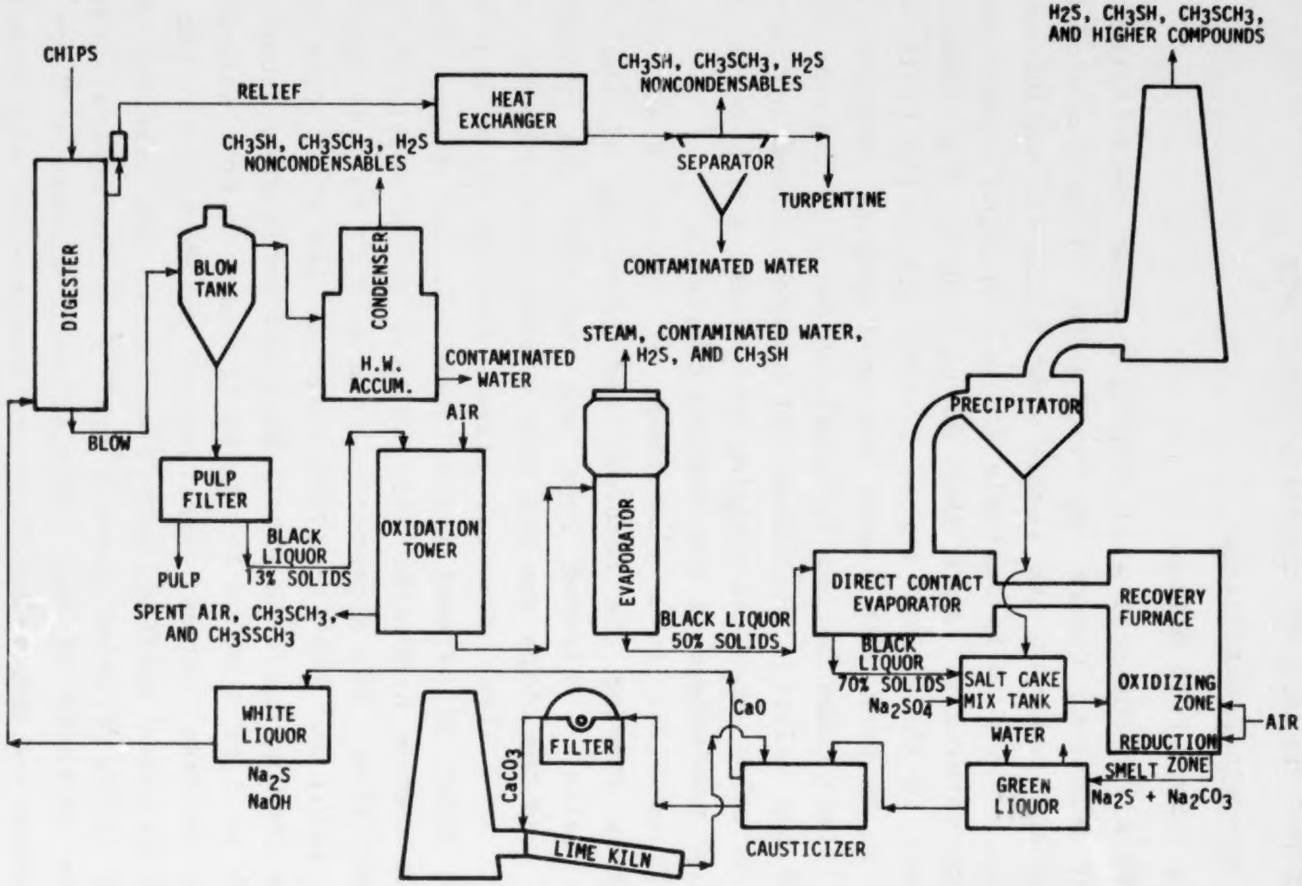
CHIPS
RELIEF
HEAT EXCHANGER
CH_3SH, CH_3SCH_3, H_2S NONCONDENSABLES
SEPARATOR
TURPENTINE
CONTAMINATED WATER
H_2S, CH_3SH, CH_3SCH_3, AND HIGHER COMPOUNDS
DIGESTER
BLOW TANK
CH_3SH, CH_3SCH_3, H_2S NONCONDENSABLES
CONDENSER
H.W. ACCUM.
CONTAMINATED WATER
STEAM, CONTAMINATED WATER, H_2S, AND CH_3SH
BLOW
AIR
PULP FILTER
PULP
BLACK LIQUOR 13% SOLIDS
OXIDATION TOWER
SPENT AIR, CH_3SCH_3, AND CH_3SSCH_3
EVAPORATOR
BLACK LIQUOR 50% SOLIDS
PRECIPITATOR
DIRECT CONTACT EVAPORATOR
RECOVERY FURNACE
BLACK LIQUOR 70% SOLIDS
Na_2SO_4
SALT CAKE MIX TANK
OXIDIZING ZONE
AIR
WATER
REDUCTION ZONE
SMELT
$Na_2S + Na_2CO_3$
GREEN LIQUOR
WHITE LIQUOR
Na_2S
NaOH
CaO
FILTER
$CaCO_3$
LIME KILN
CAUSTICIZER

Figure 3.2-1. Typical kraft sulfate pulping and recovery process.

are sent to a filter that separates the pulp from the spent cooking liquor, now called "black liquor." The pulp passes on for further refining and possibly bleaching before it is pressed, dried, and sold as pulp or made into paper or other products.

Satisfactory economics for the Kraft process require efficient recovery of sodium and sulfur values from the black liquor, as depicted on the flow sheet. The organic sulfides, also called "reduced sulfur" or "mercaptans," are often oxidized as an air pollution control measure to render them less volatile and thus diminish loss when a direct contact evaporator is used in subsequent steps. The black liquor is then concentrated to 50 percent solids in a multiple-effect evaporator and pumped to the recovery furnace.

At the recovery furnace the black liquor is concentrated to 70 percent combustible solids, in the case of direct contact evaporation, by countercurrent flow against hot combustion gases from the furnace. If good oxidation is obtained upstream, this unit will emit only small quantities of volatile reduced sulfur compounds.

The black liquor concentrate is sprayed into the recovery furnace, where the carbon from the wood is burned, the remaining water is evaporated, and the sodium is changed to molten sodium carbonate or sodium sulfide. These molten salts, or "smelt," are redissolved in water to form "green liquor," then are clarified and causticized with lime.

The calcium carbonate resulting from causticizing is filtered from the "white liquor" and is passed on to an oil- or gas-fired kiln. Entering the kiln at 35 percent moisture, the calcium carbonate is dried and then decomposes at about 1300°C (2370°F) to calcium oxide and carbon dioxide. The "white liquor" is recycled to the digester.

3.2.1.2 Lime Kiln--

The lime kiln is essential to the system of recycling caustic soda for reuse in digestion. It receives lime "mud" or calcium carbonate and burns it to quicklime (calcium oxide), which, after being slaked, is allowed to react with sodium carbonate in the green liquor to make the caustic soda.

Most lime kilns used by pulp mills are of the rotary type and are constructed of refractory-lined steel. They are 2.4 to 4 m (8 to 13 ft) in diameter and 38 to 122 m (125 to 400 ft) long.[4] They are inclined, and the lime mud is fed into the elevated end, where it contacts the counterflow of combustion gases from an oil- or gas-fired burner located at the opposite end. The kiln rotates slowly, at about 0.5 to 1.0 rpm. As it moves down the inclined kiln, the mud dries, agglomerates into pellets, and finally is calcined into calcium oxide in the hot zone of the kiln. The fresh, hot lime pellets are discharged at the lower end of the kiln and usually are slaked immediately.[6]

The lime kiln has several major limitations. It is not efficient in the use of heat; the burnt lime product may vary widely in its subsequent reactivity; and unless the sodium content of the mud is kept at 0.25 percent or higher, large loose balls or rings of lime adhere to the inner surface of the kiln and cause stoppages. Efforts have been made to improve the energy efficiency, the reactivity of the lime product, and the operability of the unit by flash-drying the mud ahead of the kiln or by calcining it in a fluid-bed unit in which time-temperature relationships can be controlled closely. Flash-dried mud enters the kiln at about 10 percent moisture. Tests run at a kraft mill in Albany, Oregon, indicated that feeding "dry mud" doubled the drying capacity of the kiln, produced a more reactive lime product, and reduced lime emission losses to 10 percent.[7] Fluid-bed calciners are in limited use, but their production rates are relatively low, about 20 to 140 Mg/day (25 to 150 tons/ day).[4] Another development, the use of oxygen to boost kiln output, should decrease the amount of dust carryover per ton of burnt lime production, because it is claimed that lime production increases 25 percent in a kiln retrofitted for oxygen enrichment. The fuel requirements per increased ton of lime output are about half that required with air alone. Advantages are reduced fuel requirement and reduced gas volume per ton of burnt lime and the attendant reduction of emissions.

3.2.1.3 Power Boilers (Bark and Combination)--

Kraft pulp mills use about 5 Mg of steam per megagram of air-dried pulp (ADP) (5 tons steam per ton of ADP).[9] Before 1960 nearly all of this steam was made at the mill in conventional oil-, gas-, or coal-fired boilers.[10] Wood waste materials, including bark, shavings, sander dust, log yard cleanup, and sawdust (often called "hogged fuel"), were burned in a tepee burner, which gave no heat recovery, had no combustion controls, and emitted large amounts of particulate. By 1973, 88 of 273 mills had at least one power boiler that could burn wood bark.[11]

Bark is difficult to burn. Depending on its source, it may contain a large percentage of ash and abrasive sand and as much as 50 percent water. Bark requires a higher temperature than conventional fuels for good combustion; if it is charged wet, it must remain in the combustion zone long enough for the water and volatiles to boil off before it ignites.

Bark char is very light, about 1/6 the weight of water. It occurs as round, flat flakes, which have a large surface to mass ratio and readily become entrained with the combustion gases.[12] Recent theoretical studies indicate that at normal flue gas velocities, char of certain particle sizes does not burn out in a conventional furnace and is always carried over.[13]

3.2.1.4 Recovery Furnace--

Figure 3.2-1 shows the position of the recovery furnace in the chemicals recovery process. Black liquor of 40 percent to 55 percent solids content from the multiple-effect evaporators is concentrated to as high as 70 percent solids in a direct-contact evaporator heated by recovery furnace flue gas. This direct-contact evaporator may be a cyclonic or venturi-type liquid-gas contactor, or it may be a cascade evaporator. Depending on the pH and temperature of the black liquor, this contactor can remove appreciable quantities of residual SO_2 from the flue gas.[14]

The black liquor concentrate is sprayed into the combustion zone of the furnace, where the organic materials burn. The chemicals, chiefly sodium salts, melt and are accumulated on a shallow hearth at the base of the furnace. The molten salts, or smelt, are subsequently dissolved in water to form green liquor, which is causticized to white liquor and recycled to the digesters.

The recovery furnace in a large, modern kraft mill can supply a major fraction of the process steam needed [as much as 5 Mg/Mg ADP (10,000 lb/ton ADP)]. It is also a major source of emissions, both particulate and the malodorous reduced sulfur compounds.[15]

3.2.2 Emissions

3.2.2.1 Lime Kiln Particulate Emissions--

The rolling and tumbling action of lime mud in a rotary kiln and the vaporization of sodium compounds in the high-temperature zone cause most of the particulate emissions. Lime dust is made up of particles ranging from 1 to 100 μm in diameter; soda fume is very small and less than 1 μm in diameter. Thus, lime particulate is relatively easy to remove and soda fume is very difficult to remove. Because sodium is held at less than 0.5 percent of the feed material, soda fume constitutes a minor percentage of the particulate generated, but its small particle size makes it a major contributor to emissions.

Stack emission data for 66 controlled and uncontrolled lime kilns were reported by 35 mills in 1973.[16] The data have limited value since the methods used to determine emissions are unknown. Averages for the 10 lowest and 10 highest emitters are given in Table 3.2-1. Reference 1, the source of most of the data, does not specify the type of fuel or the control equipment, if any,

TABLE 3.2-1. LIME KILN PARTICULATE EMISSIONS

	Emission concentration,		Weight rate of emission[b],	Ratio of flue gas rate to pulp production,	
	g/m^3, dry	(gr/dscf)	kg/Mg ADP	m^3, dry/Mg ADP/day	(scfm/ton ADP)
Lower 10 emitters[17]					
Average	0.08[a]	(0.037)[a]	0.1	0.91	(29)
Range	0.02-0.21[a]	(0.01-0.09)[a]	0.037-0.26		
Higher 10 emitters[17]					
Average	2.70[a]	(1.18)[a]	5.9	1.72	(55)
Range	0.57-9.16[a]	(0.25-4.0)[a]	2.59-21.5		
NSPS, Sept. 24, 1976					
Gas fuel	0.15	(0.065)			
Oil fuel	0.30	(0.130)			
Emission factor[15]					
Untreated			22.5		
Scrubber			1.5		

Explanation of abbreviations:
g/m^3, dry is grams of particulate per dry standard cubic meter of exhaust gas.
gr/dscf is grains of particulate per dry standard cubic foot of exhaust gas.
kg/Mg ADP is kilograms per megagram of air-dried pulp.
m^3, dry/Mg ADP/day is dry standard cubic meters per minute per megagram of air-dried pulp per day.

[a] Method of stack test unknown.

[b] Equivalent to pounds per 1000 pounds ADP.

used by each of the reporting mill operators. It can be assumed that many of the large emitters were older mills using inadequate control equipment. These data are now about 5 years old; probably the larger emitters have now modified their kiln systems to reduce emissions. Table 3.2-1 also shows that the higher emitters vent nearly twice the flue gas per unit weight of air-dried pulp produced.

3.2.2.2 Power Boilers (Bark and Combination), Particulate Emissions--

Emissions from bark-fired (hogged-fuel) boilers and boilers burning combinations of bark plus oil, gas, or coal are chiefly ash and unburned wood particulate. Emissions also include some "tramp" sand caught in the bark during logging and transport of the pulpwood. This sand has little visibility in the stack gas, but it does contribute weight. Coal used as an auxiliary fuel will contribute fly ash the same as if the coal were burned alone. Neither oil nor wood contains appreciable ash. Because of the low density and airfoil shape of wood fuels, it is easy for certain sizes of wood-carbon particulate, perhaps incandescent, to be swept out the stack.

The type of auxiliary fuel used probably affects particulate emissions: tests at one mill showed that the combination of natural gas and bark gave the lowest emissions, followed in order by oil and coal.[18]

Review of the recent literature on hog-fueled boilers indicates that although no single design optimizes emissions, certain design and operational practices can help reduce them. These include predrying of wood fuel, control of fly ash reinjection, and proper adjustment of overfire and underfire air, which are discussed more fully in the Controls section.

Uncontrolled emissions from power boilers range from 25 to 37.5 g/kg of bark fired (50 to 75 lb/ton).

3.2.2.3 Recovery Furnace, SO_2 Emissions--

As shown in Figure 3.2-1, flue gases from the recovery furnace in a typical kraft pulp mill go to a direct-contact evaporator and the combined vapors then go to an electrostatic precipitator prior to discharge. To date, operators have shown little concern about SO_2 emissions from the recovery furnace. Even though concentrations of SO_2 from the recovery furnace may be as high as 700 to 800 ppm, the contact evaporator usually reduces this to 50 to 100 ppm before the gas reaches the stack. Attention has been focused on emissions of total reduced sulfur (TRS) and of particulate, which apparently are considered much more serious. Most of the literature on control of recovery boiler effluents deals with these two kinds of emissions.

Emissions of SO_2 from recovery furnaces are a function of operating parameters, as discussed in the Controls section.

3.2.3 Control Measures

3.2.3.1 Lime Kiln Particulate--

Wet scrubbers, usually venturi or impingement-type, are the most common devices used in the kraft pulp industry to control lime kiln particulate emissions.[19] The venturi scrubber is more efficient (97 to 99%), but it requires a higher pressure drop [2.5 to 7.5 kPa (10 to 30 in. H_2O)] than the impingement-type scrubber [1 to 2 kPa (4 to 8 in. H_2O)].[20]

Three process changes (described briefly at page 3.2-4) are reported to be effective in reducing lime kiln emissions. The predrying of lime mud before calcination, the use of oxygen to boost lime kiln output and fluid-bed calcination reportedly reduce lime losses per unit of throughput, provide energy savings, and increase production. None of the literature indicates that all of these steps have been applied together in a single operating mill. Such modifications would be most feasible at new installations and are worthy of consideration in devising an overall control methodology for a new lime kiln facility.

EPA Method 5 tests on lime kilns have shown that emissions can be controlled to 0.07 g/m^3, dry (0.03 gr/dscf) on a gas-fired unit[21] and to 0.21 g/m^3, dry (0.09 gr/dscf) on an oil-fired unit.[22] The control devices in both instances were venturi scrubbers with pressure drops in the range of 5 to 6 kPa (20 to 24 in. of water).

3.2.3.2 Power Boilers (Bark and Combination) Particulate Control--

In general, current practice is to control bark-fired and combination-fired boilers by the use of dry mechanical cyclones as the primary control device, followed by a scrubber, baghouse, electrostatic precipitator or granular filter (dry scrubber) for secondary control. Because the use of bark-burning boilers is relatively new to the paper industry[10] and involves some unusual combustion problems,[12] the variety of secondary control devices in use is not surprising. In combination boilers, the auxiliary fuel and furnace design also affect selection and performance of the secondary control device.

In addition to the add-on control devices, certain practices in the design of the bark furnace and in the preparation of bark fuel can reduce the loading in the exhaust stream:

- Design for temperature of the combustion zone to be maintained at or above 1093°C (2000°F) to improve burning of the wood carbon.
- Reduce flue gas velocity, and hence the entrainment of very light wood particles, by careful control of excess air. Predrying the wood also reduces particle reentrainment, and it reduces the moisture content of the fuel.
- Control particle-size range of freshly hogged wood fuel and of reinjected fly ash so that these materials will not pass through the furnace without burning. The quantity of particles sized below 0.3 mm should be limited.

As noted earlier, the furnace design must take into account the control devices to be used. For instance, if a baghouse is proposed, care must be taken to ensure against incandescent particles reaching the bags and damaging them. Electrostatic collectors may achieve desired performance only when coal is fired with the bark. The average of emissions from the five best-controlled combination bark-fuel boilers (data for 26 units reporting in 1973) was 3.9 g/Mg (7.8 lb/ton) of bark fired. These values are equivalent to 0.17 g/GJ (0.4 $lb/10^6$ Btu) or 0.4 g/m^3, dry (0.18 gr/dscf). As indicated in Table 3.2-2, various control technologies have reduced emission rates markedly since 1973. Table 3.2-2 also illustrates the general effect on emissions when gas, oil, and coal are used as auxiliary fuels.

3.2.3.3 Recovery Furnace, Sulfur Dioxide Emissions Control--

A number of variables in recovery furnace operation can affect SO_2 emissions. One investigator has shown how control of turbulence, secondary air, and spray-droplet size can reduce SO_2 in recovery furnace flue gas to near zero.[27] Another has found that simply holding excess oxygen to 3 percent reduces SO_2 levels to 25 ppm.[28] One theoretical study points out that very small changes in sulfur or sodium emissions inside the furnace can give rise to very large excursions in SO_2 concentration.[29] A series of tests showed that SO_2 emissions from a recovery furnace could be held at 50 to 100 ppm.[30] Concentrations of SO_2 ranged from 5 to 100 ppm in combined exhausts from the recovery furnace and contact evaporator at a North Carolina mill.[31] Measured SO_2 emissions in the furnace exhaust ranged from 0 to 200 ppm (55 ppm average) at an Alabama mill.[32] A summary of these literature citations indicates that the following operating conditions tend to minimize SO_2 emissions:

- Holding excess oxygen at or above 3 percent
- Injection of large spray droplets of black liquor in the furnace

TABLE 3.2-2. PARTICULATE EMISSIONS FROM POWER BOILERS (BARK AND COMBINATION)

Fuel	Controls	Average emissions, g/m^3, dry	(gr/dscf)	Reference (date)
Bark and coal[a]	Cyclone, ESP	0.026	(0.012)	23 (1978)
Bark and gas	Multicyclones and wet scrubber	0.032	(0.014)	
Bark and oil		0.126	(0.055)	
Bark and coal		0.137	(0.06)	18 (1974)
Bark	Fabric filter	0.069	(0.03)	24 (1978)
Bark	Multicyclones/scrubber	0.032	(0.014)	
Bark	Multicyclones/venturi	0.037	(0.016)	
Bark and oil	Cyclone/wet scrubber	0.059	(0.026)	25 (1978)
Bark	Granular filter (dry scrubber)	0.105	(0.046)	
Bark and oil	Granular filter (dry scrubber)	0.158	(0.069)	
Bark[b]	Granular filter with electrostatic mode	0.018	(0.008)	26 (1978)

[a] 60 to 65 percent coal, 35 to 40 percent bark.

[b] Full-sized demonstration unit operated on a portion of the exhaust stream from a 100 percent bark-fired boiler.

- A high percentage of solids in the liquor
- A ratio of sulfur to sodium below 0.5:[1]
- High turbulence at the secondary air inlet ports

Recent information on factors that affect SO_2 emissions from kraft recovery furnaces indicate that sulfidity plays a dominant role.[33,34] Lower sulfidity levels (20 to 24 percent) have adverse effects on pulp quality and increase safety problems; medium levels (25 to 30 percent) allow these problems to be averted, and sulfidity levels in excess of 31 percent sharply increase SO_2 emissions. This information indicates that optimum process control--limiting sulfidity levels to 30 percent and keeping furnace operating conditions close to optimum--will keep the 24-hour average emission rate below 250 ppm and the monthly average rate to about 100 ppm.

The possibility of using flue gas desulfurization (FGD) to reduce SO_2 emission levels from recovery furnaces was examined.[34] It was concluded that available FGD systems have successfully controlled sources having gas volumes and SO_2 concentrations comparable to those of kraft recovery furnaces; FGD is therefore considered "available technology." Although no detailed cost analysis was made, capital cost was estimated to be about $5000/ton per day of furnace capacity, and annual cost was estimated to be $1600/ton per day of furnace capacity.

In summary, recovery furnace operating conditions can influence SO_2 emissions, and optimization of operating conditions will curtail these emissions. The sulfidity level plays a major role: the higher the sulfidity, the greater the SO_2 emissions. The type of pulp or paper manufactured affects the sulfidity level in the process. For lower-sulfidity pulp, attentive control of sulfidity levels (optimum process control) results in minimum SO_2 emissions. Flue gas desulfurization has been used to control sources comparable to recovery furnaces in gas volume and concentration; therefore EPA considers FGD to be "available technology" for the control of SO_2 emissions from recovery furnaces. On recovery furnaces operating at high sulfidity levels, FGD offers a means of reducing SO_2 emissions.

3.2.4 Emission Limits

This section summarizes emission limitations categorized by state implementation plans (SIP), new source performance standards (NSPS), and achieved-in-practice (AIP) levels for lime kilns, power boilers, and recovery furnaces.

3.2.4.1 Lime Kiln, Particulate Emissions--

The NSPS for lime kilns in Kraft pulp mills are set at 0.15 and 0.30 g/m^3, dry (0.067 and 0.134 gr/dscf) for gas- and oil-fired units, respectively. These are approximately equivalent to 0.27 and 0.59 kg/Mg ADP (0.54 and 1.08 lb/ton ADP).

In six states having major Kraft pulp producers, the SIP limit for particulate emissions from lime kilns is the same and is the most stringent of all the SIP limits. This limit is 0.5 kg/Mg ADP (1.0 lb/ton ADP), equivalent to 0.28 g/m^3, dry (0.122 gr/dscf), with distinction regarding the type of fuel fired. Thus, the SIP limit for oil-fired kilns is slightly more stringent than the NSPS.

The lowest AIP emission levels are well below SIP and NSPS limits. Emissions from gas-fired lime kilns have been controlled to 0.07 g/m^3, dry (0.03 gr/dscf). Oil-fired kilns have been controlled to 0.21 g/m^3, dry (0.09 gr/dscf).

3.2.4.2 Power Boilers, Particulate--

No NSPS have been promulgated for bark-fired boilers serving kraft pulp mills.

The most stringent SIP limitation is that of Florida: 0.047 kg/GJ input (0.1 lb/10^6 Btu input), which is roughly approximated as 0.09 g/m^3, dry (0.04 gr/dscf).

The BACT level proposed by EPA Region X is 0.09 g/m^3, dry (0.04 gr/dscf). This BACT proposal is based on a fabric filter installation on a hogged-fuel power boiler for which tests have indicated particulate emissions of 0.069 g/m^3, dry (0.03 gr/dscf) with 100 percent bark-firing.[22]

The AIP levels vary with the type of fuel or fuel combinations fired and the control device applied. Information sufficient for full definition of the relationship and impact of varying fuels and fuel combinations on emission levels is not available. Table 3.2-3 reflects the better AIP levels that have been reported. These AIP levels appear to be significantly lower than SIP or NSPS limitations.

3.2.4.3 Recovery Furnace, SO_2 Emissions--

No NSPS are applicable to SO_2 emissions from recovery furnaces.

Although SIP's do not specifically limit SO_2 emissions from recovery furnaces, they do contain regulations covering all new sources. The most stringent SIP limits are 300 ppm SO_2, typical of California and Oregon regulations.

The BACT level proposed by EPA's Region VI is 250 ppm SO_2 for the paper mill at Morrilton, Arkansas, including the recovery furnace.

The lowest AIP levels from recovery furnaces, achieved by optimizing process conditions, have been 0 to 25 ppm SO_2; excursions to 100 to 200 ppm are common, however, even under these optimum conditions.

The AIP levels are significantly lower than SIP or BACT limits. It is not known whether SO_2 emissions from most recovery furnaces can be reduced to the lowest SIP levels. AIP levels cannot be compared directly with SIP or BACT limits, since the latter include all emissions from the paper mills.

3.2.5 Determination of Lowest Achievable Emission Rate (LAER)

The recommended limitations are based on SIP's and on performance information available in early 1979. It is anticipated that several additional SIP regulations covering these sources will be promulgated and/or modified in 1979 and 1980 and that appreciable new performance data will become available in the near term. Conceivably, some SIP regulations may be more stringent than the LAER suggested herein. Furthermore, performance testing may show that more stringent limits than those suggested are feasible or it may show that the suggested limits are appropriate or that they are not achievable for some specific subcategories. In any case, the basis for determining LAER for many source categories is expected to change frequently. Since LAER is near the vanguard of control technology, a more detailed analysis is particularly necessary when addressing modified or reconstructed facilities subject to the provisions of Section 173 of the Clean Air Act. Emission limitations reasonable for new sources may in some instances be economically or technically unreasonable when applied to modified or reconstructed sources of the same type.

The LAER levels recommended for each process pollutant are based on AIP emissions. These recommendations are summarized in Table 3.2-3.

TABLE 3.2-3. RECOMMENDED LAER FOR KRAFT PULP MILL PROCESSES

Process	Pollutant	Recommended LAER
Lime Kilns	Particulate	
Gas-fired		0.07 g/m^3, dry (0.03 gr/dscf)
Oil-fired		0.21 g/m^3, dry (0.09 gr/dscf)
Power Boilers	Particulate	
Auxiliary gas-fired		0.032 g/m^3, dry (0.014 gr/dscf)
Auxiliary oil-fired		0.059 g/m^3, dry (0.026 gr/dscf)
Auxiliary coal-fired		0.026 g/m^3, dry (0.012 gr/dscf)
100% bark-fired		0.032 g/m^3, dry (0.014 gr/dscf)
Recovery Furnace	Sulfur dioxide	50 ppmv daily average 100 ppmv - 3 hour maximum

3.2.5.1 Lime Kiln, Particulate--

The recommended LAER values are based on achieved-in-practice levels. The suggested value for gas-fired kilns is 0.07 g/m^3, dry (0.03 gr/dscf) and for oil-fired units, 0.21 g/m^3, dry (0.09 gr/dscf). The literature reports process changes such as predrying of lime muds, use of oxygen, and fluidized-bed calcination could provide benefits in the form of energy conservation, production increase, and emission reduction. Such process changes should be considered along with a high-pressure-drop venturi or another equally effective device when devising an overall control strategy to attain the lowest achievable emission rate.

3.2.5.2 Power Boilers (Bark and Combination), Particulate--

The fuel or fuel combination fired affects the quantity of particulate emissions from power boilers, the type of control used, and the performance of that control. Although available stack test data are insufficient to define this relationship fully, the reported AIP levels provide a basis for LAER determinations. The suggested LAER values are as follows: for 100 percent bark fired boilers, 0.032 g/m^3, dry (0.014 gr/dscf); for gas/bark-fired, 0.032 g/m^3, dry (0.014 gr/dscf); for oil/bark-fired, 0.059 g/m^3, dry (0.026 gr/dscf); and for coal/bark-fired, 0.026 g/m^3, dry (0.012 gr/dscf). Depending on fuel composition and fuel mix, a LAER value more or less stringent than that suggested may be appropriate on a case by case basis.

3.2.5.3 Recovery Furnace, SO_2--

It is recommended that LAER be set at a maximum value of 50 ppm by volume on a daily average basis, with excursions allowed to 100 ppm over a period of no more than 3 hours in any 24-hour period. Pulp or paper manufacturing of the low-sulfidity type can meet this or a lower limitation by attentive control of process variables. Operation at high sulfidity levels may require the application of FGD technology in addition to optimum process control to meet the LAER limitation.

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3.3 MAJOR SOURCE CATEGORY: ELECTRIC ARC FURNACES AT STEEL FOUNDRIES AND GRAY IRON FOUNDRIES; PARTICULATE, ONLY: CHARGING (AND BACKCHARGING AT STEEL FOUNDRIES) AND TAPPING.

3.3.1 Process Description

Castings made of iron or steel are solid solutions of iron and carbon to which various amounts of alloying elements have been added. The carbon content of the finished casting is what distinguishes iron from steel; irons typically contain 2 to nearly 4 percent carbon, whereas steels contain less than 2 percent carbon.

The direct arc furnace is widely used today in both iron and steel foundries.[1] The furnace is usually charged with solid scrap, iron, or steel, although molten pig iron from a blast furnace or prereduced iron pellets sometimes form part of the charge. An electric arc furnace (EAF) is a cylindrical refractory-lined vessel, above which are suspended three carbon electrodes that can be lowered through the furnace roof to a position above the charged materials. These electrodes can be retracted, and the furnace roof can be rotated aside to permit charging. Alloying agents and slagging materials are usually added through doors in the side of the furnace. Once the charge is in place, the electrodes are lowered into the furnace and current is switched on. Arcing of current from the electrodes into the scrap generates heat to melt the scrap.

When the charge is melted and the temperature is adjusted, the slagging operation is begun. In slagging, the carbon and oxygen contents are adjusted to the values desired for the iron or steel product. Molten slag is withdrawn from the furnace and various elements are added--carbon to the iron and possibly iron oxide to the steel.

When the desired chemistry has been achieved, the electrodes are lifted out and the furnace is tilted as much as 45 degrees towards the ladle that receives the furnace charge. The hot steel or iron is then poured from the ladle into holding furnaces or directly into sand molds, from which, after cooling, the rough casting is taken for cleaning, possibly annealing, and other finishing operations. Figure 3.3-1 shows the process flow in a typical iron foundry that uses an EAF as the melting vessel.[2] Except for the cupola, which is not used in a steel foundry, Figure 3.3-1 also represents the process flow in a steel foundry.

3.3.2 Emissions

Production of steel or of gray iron for castings from an EAF is a batch process in which the following steps generate significant emissions:

1. Charging the furnace. Scrap metal is the major material, plus additives such as "carbon raiser," ferro silicon (for gray iron), and limestone and coke (for steel). The roof is open.

2. Meltdown operations. These include unscheduled occurrences such as "cave-ins" of unmelted material from the furnace walls into the molten pool and "pulling bottom," which is undesired boring into the furnace bottom by electrodes lowered too far. This category also includes scheduled operations such as "backcharging" (usually for steel), which is the addition of a large quantity of additional scrap to the molten bath immediately after the first charge is partially melted. The roof is closed during meltdown; charging doors, or the roof itself, is opened during "backcharging."

3. Oxygen lancing, in steelmaking furnaces only. The roof is closed.

4. Slagging, refining, and "working the heat," during which the steel or iron is brought to the proper composition and temperature. Some alloy steels require a second or reducing slag, which must be accomplished with minimum induction of air. The roof is closed; the furnace is tilted to remove slag.

5. Reestablishment of the arc after an interruption. The roof is closed.

6. Tapping of the metal into a ladle. The roof is closed; the furnace is tilted.

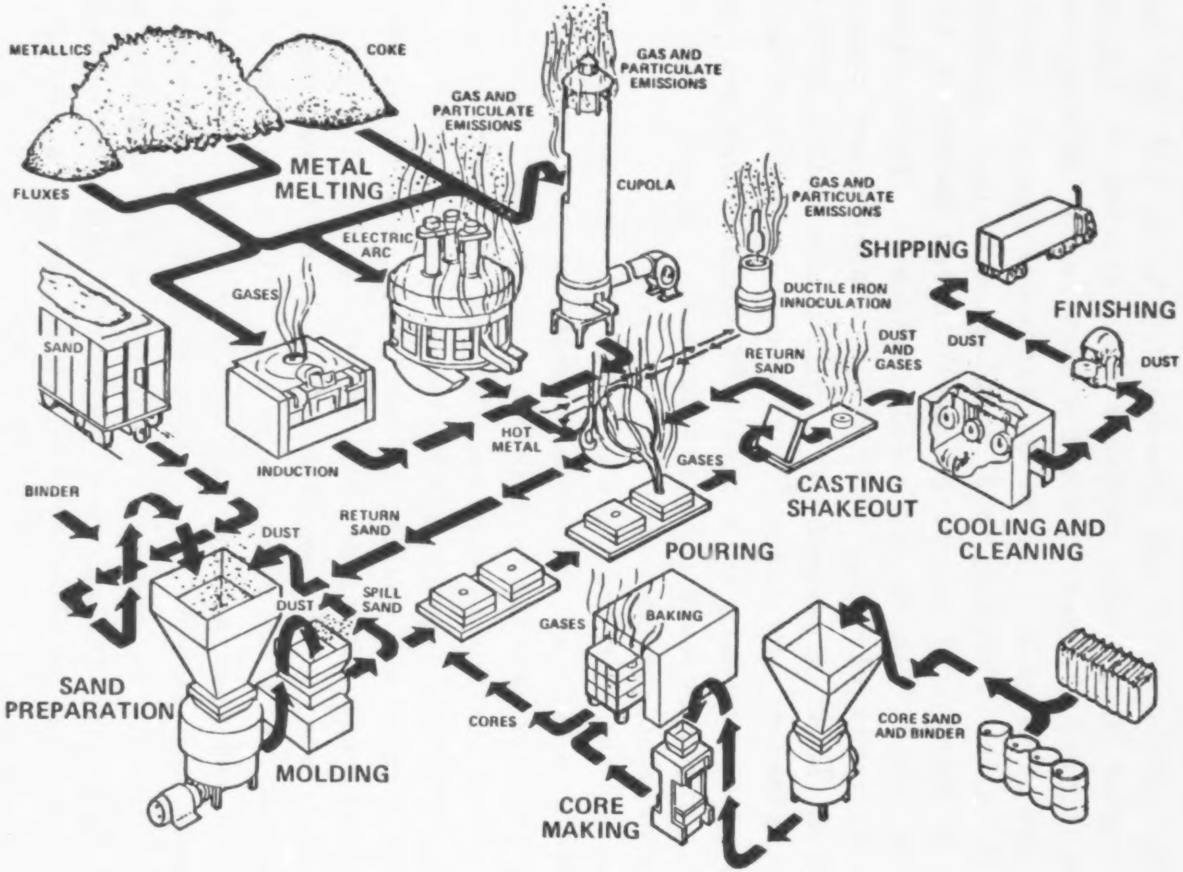
METALLICS
COKE
FLUXES
METAL MELTING
GAS AND PARTICULATE EMISSIONS
GAS AND PARTICULATE EMISSIONS
CUPOLA
GAS AND PARTICULATE EMISSIONS
ELECTRIC ARC
GASES
SHIPPING
DUCTILE IRON INNOCULATION
FINISHING
SAND
DUST
DUST
DUST AND GASES
RETURN SAND
HOT METAL
INDUCTION
GASES
BINDER
CASTING SHAKEOUT
COOLING AND CLEANING
RETURN SAND
DUST
POURING
DUST
SPILL SAND
GASES
BAKING
SAND PREPARATION
CORES
CORE SAND AND BINDER
MOLDING
CORE MAKING

Figure 3.3-1. Iron foundry process flow and emission sources.[2]

In the following discussion the distinction between iron and steel foundries is made only when the EAF emissions differ significantly. During melting and refining, uncontrolled particulate emissions from iron furnaces range from 2 to 20 kg/Mg (4 to 40 lb/ton) of iron charged and average 7.0 kg/Mg (14 lb/ton). The emission rates from steel furnaces are reported to average 8.0 kg/Mg (16 lb/ton) charged. Emission factors for charging and tapping are not available. Based on extrapolation of limited emission test data, charging and tapping emissions together account for 10 percent of the total uncontrolled emissions (0.7 kg/Mg for iron and 0.8 kg/Mg for steel furnaces). These values assume alloying takes place in the ladle. Charging and tapping are estimated as about 5 percent of total furnace emissions when no alloys are added to the ladle.[3] It is to be noted that emissions may vary considerably as a result of furnace type and age, the kinds of scrap processed, the additives to the melt, and the types of iron or steel products.

Rotation of the furnace roof to the side during charging renders ineffective all of the close-coupled evacuation systems during this period of intense emissions. Most of these emissions are due to oil on the scrap, sand embedded in the recycled castings, and miscellaneous organic materials and dirt. Tests of the effects of cleanliness and quality of scrap on intensity of emissions have shown that emissions doubled when dirty, low-quality scrap was used.[4] When a 5-ton-per-heat gray-iron EAF was charged with scrap wetted to 1 weight percent with oil, more than 9 kg (20 lb) of soot and dust was emitted in a short time. Emissions during charging and tapping of a steel furnace are perhaps 10 percent of the total. In contrast, emissions during charging and tapping of a gray iron EAF can be 5 percent of the total. Emissions during tapping are usually negligible unless alloying in the ladle is practiced.[2]

During meltdown the charge is rapidly brought up to temperature; all remaining oil and some volatile nonferrous metals such as lead, zinc, and magnesium are expelled. "Cave-ins" and "pulling bottom" can exacerbate these meltdown emissions beyond the volume capacity of the ventilation system. Since the roof covers the furnace during this period, however, adjustment of electrode positioning and of power input should hold the emissions to a level that is controllable by a well-designed ventilation and particulate capture system. In "backcharging," which is common practice with steel EAF's, the cold metal scrap produces a violent eruption when it hits the molten pool, and the amount of pollutants generated at this time is probably higher than at any other time during the heat. Because charging doors must be opened, or the entire roof rotated away, capture of these intense emissions is incidental.[5]

Oxygen lancing, used in steel furnaces, helps remove carbon and accelerates the melting process. Although oxygen generates gaseous emissions of carbon monoxide and carbon dioxide and increases the potential for particulate emissions, the practice of careful control of oxygen rate (to maintain the correct chemistry of the heat) and keeping the furnace roof closed during lancing should minimize escape of particulates. Near the end of the lancing period, some iron oxidizes to a highly visible, fine red fume that is most difficult to capture. During the peak of oxygen lancing, the emission rate has been measured at 2 to 3 times that occurring during average furnace operation.[2]

Slagging is done once per heat in producing gray iron, but may be required twice to make certain alloy steels. This second slagging must be done with minimum inleakage of air, i.e., ventilation must be stopped or heavily restricted within the furnace. During this period, fumes escape upward through the electrode holes and into the foundry building bay area. Emissions during the first slagging are less pronounced (via the electrode holes). They are more pronounced in furnaces with direct shell evacuation than on furnaces with side draft hood evacuation. The operations of refining and working the heat, which are combined with the second slagging, are done principally in producing steel castings where standards for soundness and strength of the casting are very high. Because this step involves only slight temperature changes and very little reaction, emissions are of moderate intensity. During the period of no furnace ventilation, slagging presents emission problems.

the customer's specifications. The resulting variations in emissions present problems in the design of control systems. Even if the operator knows the solvent compositions, exhaust volume and controls must be based on the most critical or difficult situation. The number of solvents used also affects the owner's ability to recover and reuse the solvent. Thus, the type of coating is an important factor in the cost of controlling emissions from a fabric coating plant.

3.5.4 Emission Limits

The initial criterion for defining LAER for a surface coating industry is the degree of emission control required by the most stringent regulation adopted and successfully enforced by a state or local air pollution control agency.

As reported elsewhere, most regulations of organic solvent emissions are patterned after what is now Rule 442 of the South Coast (California) Air Quality Management District.[7] Review of regulations in the 16 states that contain about 85 percent of all surface coating industries showed them to be essentially the same as Rule 442.[8] Indiana has the most stringent regulation in that it limits organic solvent emissions to 1.4 kg/h (3 lb/h) or 6.8 kg/day (15 lb/day) unless such emissions are reduced by at least 85 percent, regardless of the reactivity or temperature of the solvent. Organic solvents that have been determined to be photochemically unreactive or that contain less than specified percentages of photochemically reactive organic materials are exempt from this regulation.

The California Air Resources Board recently adopted a model rule for the control of VOC emissions from paper and fabric coating operations.[9] This model rule, which must be met 3 years from the date of adoption, limits VOC emissions from the coating line to 120 g solvent/liter (1.0 lb/gal) of coating minus water. This is to be accomplished by the use of add-on control equipment

Hoods must be designed to maximize pollutant capture with low air inleakage and without creating significant operational and maintenance problems. Direct shell evacuation, or "fourth-hole," systems are effective and simple, allowing minimal inleakage. Roof hoods and direct shell evacuation are alternative controls, although roof hoods are no longer being installed. These systems for pollutant capture have been available and in use for many years in both iron and steelmaking.

Side-draft hoods mounted on the furnace roof are used with gray iron and smaller steel foundry furnaces.[2] One side is open to provide maintenance access to the electrodes. These hoods are effective in collecting fumes escaping via the electrode holes. This type of hood does require larger exhaust volumes than do roof hoods or direct furnace evacuation systems, but these larger volumes reduce temperature at the control device and assure complete combustion of carbon monoxide.

Fabric filter collectors (baghouses) are regarded as the most efficient and versatile device for removal of particulates in the exhaust from EAF's. Major control system components consist of an exhaust fan, a cooler to reduce the temperature of the hot gases so that they will not damage bag fabrics, and a baghouse. Filter velocities are as low as 1.1 cm/s (2.1 ft/min) and as high as 1.3 cm/s (2.55 ft/min).[5] Wet scrubbers and electrostatic precipitators appear applicable to EAF particulate control, but neither device has been widely used by U.S. foundries.[2]

A number of process and/or equipment changes have been proposed that would reduce emissions and in some cases save energy.[2] These include a closed charging system, preheating of scrap to drive off oil and moisture, a hooded charge bucket, a hooded tapping ladle, degreasing of scrap, and the use of an enclosure around the furnace. Of these, only the enclosure or shroud has been tried in the United States, and this installation is on steelmaking furnaces of 60-ton capacity.[6]

3.3.4 Emission Limits

1. Standards of Performance for New Stationary Sources (NSPS), Electric Arc Furnaces in the Steel Industry; Federal Register,

Tuesday, September 23, 1975. These standards apply to steelmaking only, and not to foundries using electric arc furnaces. The following pertinent sections of this NSPS for steelmaking provide a reference point for emission limits from foundries.

> "...no owner or operator....shall cause to be discharged... from an electric arc furnace any gases which:
>
> (1) Exit from a control device and contain particulate matter in excess of 12 mg/dscm (0.0052 gr/dscf)
>
> (2) Exit from a control device and exhibit 3 percent opacity or greater.
>
> (3) Exit from a shop and, due solely to operations of any EAF's, exhibit greater than zero percent shop opacity except:
>
> (i) Shop opacity greater than zero percent, but less than 20 percent, may occur during charging periods.
>
> (ii) Shop opacity greater than zero percent, but less than 40 percent, may occur during tapping periods."

Identical standards were adopted by California South Coast (12-3-1976) and California Bay Area for facilities modified or built after October 21, 1974, again for electric arc steelmaking and not for steel or iron foundries.

Figure 3.3-2 illustrates the relationship of emission limits on EAF's as specified in NSPS and in the state regulations of California, Pennsylvania, and New Jersey. For comparison purposes, it shows the achieved-in-practice (AIP) emission levels at six steel and six iron foundries.[2,5] The values represent particulate concentration (g/m^3, dry) in the exhaust from the control device. In Figure 3.3-3 the data are presented on the basis of mass emission rate (kg/h). The figures indicate that most AIP values, especially at production rates of 10 Mg/h, are lower than either the SIP requirements or NSPS for steelmaking.

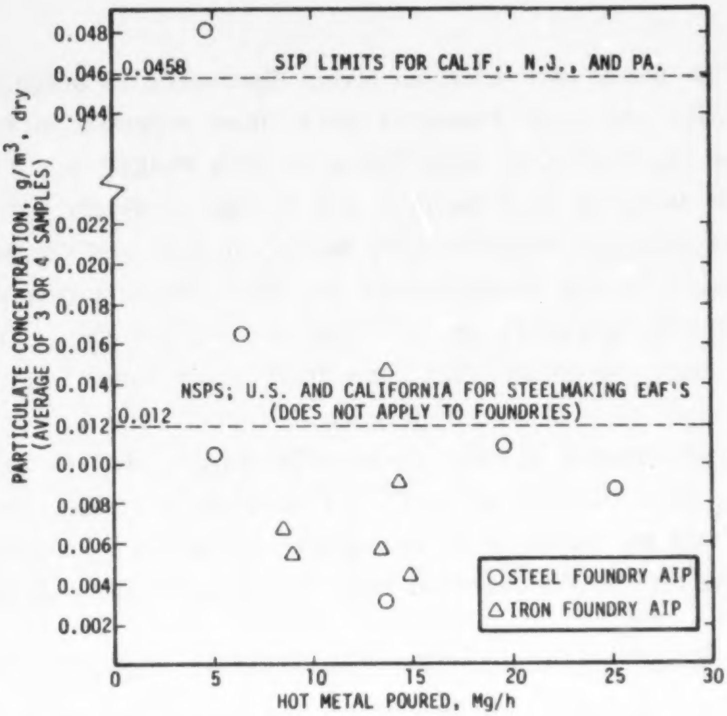

Figure 3.3-2. Particulate concentration versus production rate.

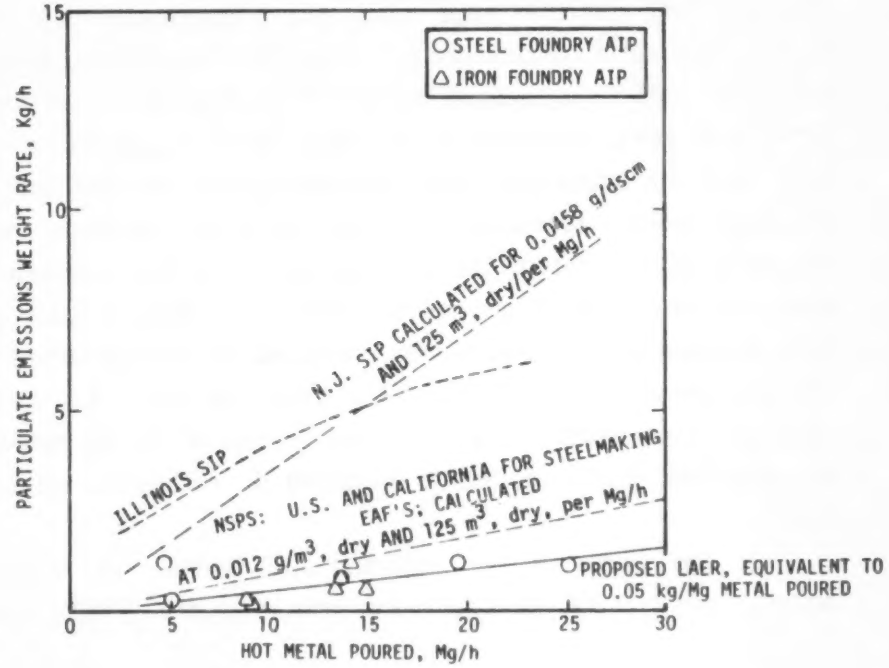

Figure 3.3-3. Particulate emissions by weight versus production rate.

The lowest AIP emission levels discovered in preparing this guideline for both iron and steel foundries were those reported in Reference 7. All test results reported here were based on EPA Method 5. This reference reports an AIP value of 11.0 mg/m^3, dry (0.0048 gr/dscf) for a new iron foundry. At a second and newer foundry having an EAF and control system design that was based on the experience of the first, the test results showed 8.9 mg/m^3, dry (0.0039 gr/dscf) at the control device outlet. In both instances the EAF's were equipped with side-draft hoods and hoods above the pouring spout and slag door. Reference 7 reports the lowest achieved values for steel EAF control systems to be 5.74 mg/m^3, dry (0.0025 gr/dscf) and 6.63 mg/m^3, dry (0.0029 gr/dscf). The capture system for both steel foundry EAF's was by direct shell evacuation. The control equipment at the iron and steel foundry EAF's reported here was a fabric filter device.

3.3.5 Determination of Lowest Achievable Emission Rate (LAER)

The recommended limitations are based on SIP's and on performance information available in early 1979. It is anticipated that several additional SIP regulations covering these sources will be promulgated and/or modified in 1979 and 1980 and that appreciable new performance data will become available in the near term. Conceivably, some SIP regulations may be more stringent than the LAER suggested herein. Furthermore, performance testing may show that more stringent limits than those suggested are feasible or it may show that the suggested limits are appropriate or that they are not achievable for some specific subcategories. In any case, the basis for determining LAER for many source categories is expected to change frequently. Since LAER is near the vanguard of control technology, a more detailed analysis is particularly necessary when addressing modified or reconstructed facilities subject to the provisions of Section 173 of the Clean Air Act. Emission limitations reasonable for new sources may in some instances be economically or technically unreasonable when applied to modified or reconstructed sources of the same type.

On the basis of the reported AIP levels, the suggested LAER is 9.2 mg/m^3, dry (0.004 gr/dscf) for iron foundry EAF's and 6.9 mg/m^3, dry

(0.003 gr/dscf) for steel foundry EAF's. These values represent the average emission limit over a complete furnace cycle, which includes charging, melting, slagging, and tapping. Because the volume of exhaust per ton of molten metal varies with the capture device used, the suggested LAER limits are in terms of control device outlet concentration rather than mass emission rate.

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3. Air Pollution Control Techniques for Electric Arc Furnaces in the Iron and Steel Foundry Industry. Guideline Series. EPA 450/2-78-024, U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. June 1978. p. 2-16.

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6. Attachment to trip report, Lone Star Steel Company, Lone Star, Texas. EPA Contract No. 68-01-4143. Sept. 14, 1977.

7. EPA 450/2-78-024, pp. A-1, A-11.

3.4 MAJOR SOURCE CATEGORY: PETROLEUM REFINERIES CATALYTIC CRACKING UNIT AND LIQUID FUEL BURNING--SULFUR DIOXIDE EMISSIONS

3.4.1 Process Description

3.4.1.1 Catalytic Cracking--

Catalytic cracking is a high-temperature, low-pressure process that converts certain heavier portions of crude oil primarily into gases, gasoline blend stocks, and distillate fuels. Feedstocks to catalytic cracking units are gas oils from atmospheric or vacuum crude oil distillation units, thermal cracking units, lube oil extraction and dewaxing units, coking units, or deasphalting units. Catalytic cracking units are normally operated to produce a maximum of gasoline blend stocks, but the units are very flexible and operating conditions can be varied to maximize other products.

As of January 1, 1978, catalytic cracking capacity in the United States as reported in the Oil & Gas Journal was 788,050 m^3 (4,956,682 bbl) per stream day.[1] Two types of catalytic cracking processes are in use today: (1) the fluid process, which uses powdered catalyst, and (2) the Houdry and Thermafor Catalytic Cracking (TCC) processes (in limited use), which use a pelletized catalyst. Of the 285 U.S. petroleum refineries, approximately 124 contain fluid catalytic cracking units, 17 contain TCC facilities, and 3 contain Houdriflow units.

A fluid catalytic cracking unit is composed of three basic sections: cracker, regenerator, and fractionator. As shown in Figure 3.4-1, the cracking reactions take place continuously in the cracking section, with the spent catalyst being continuously regenerated and returned to the cracking section. Both the cracking and regeneration sections operate on the fluidization principle, which makes possible a continuous flow of catalyst as well as hydrocarbon feed. Gas oil feedstock is mixed with the hot catalyst and introduced into the cracker. Steam is added at the base of the cracker to strip and purge the spent catalyst of

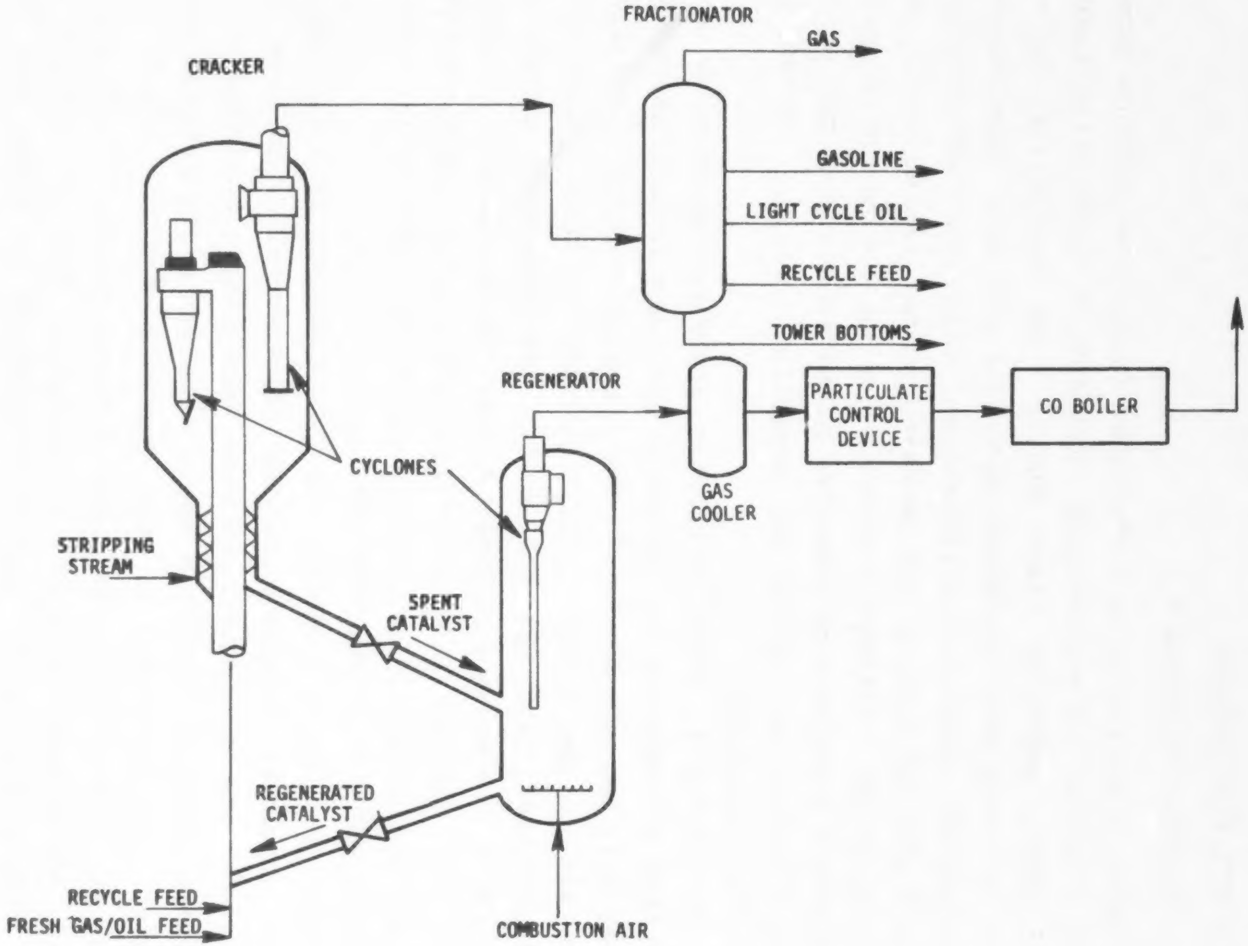
FRACTIONATOR
GAS
CRACKER
GASOLINE
LIGHT CYCLE OIL
RECYCLE FEED
TOWER BOTTOMS
REGENERATOR
PARTICULATE CONTROL DEVICE
CO BOILER
CYCLONES
GAS COOLER
STRIPPING STREAM
SPENT CATALYST
REGENERATED CATALYST
RECYCLE FEED
FRESH GAS/OIL FEED
COMBUSTION AIR

Figure 3.4-1. Generalized schematic of a fluid catalytic cracking unit.

adsorbed hydrocarbons. The hydrocarbon products are withdrawn from the top of the cracker and sent to a fractionator for separation into product streams.

The coke-laden spent catalyst is withdrawn from the base of the cracker and transferred to the regenerator. A controlled amount of air is introduced into the regenerator with the catalyst to burn the coke, which reheats the catalyst. The resulting combustion gases are channeled through a series of cyclone separators located inside the regenerator to remove most of the entrained catalyst fines. The remaining catalyst fines can be removed from the gases by electrostatic precipitators or a third-stage cyclone separator outside the regenerator. The regenerated catalyst is withdrawn from the bottom of the regenerator vessel and returned to the cracker to complete the cycle.

The hot flue gases, at about 538°C (1000°F) contain 5 to 10 percent carbon monoxide (CO), which generally is burned in a CO or waste heat boiler to recover a considerable amount of energy. The CO boiler is located either upstream or downstream of the electrostatic precipitator. If the CO boiler is downstream of the electrostatic precipitator, the flue gas must be cooled to less than 315°C (600°F) in a cooler before entering the electrostatic precipitator. Gases leaving the CO boiler are discharged to the atmosphere and can be a source of air pollution.

The hydrocarbon product vapors leaving the fluid catalytic cracker are sent to a fractionator for the first separation of products into gases, gasoline, and cycle oils. These streams are further separated in the refinery as needed. Typical operating ranges and yields for a fluid catalytic cracker are as follows:

Temperature, °C (°F)	460° to 524°C (860° to 975°F)
Pressure, kPa (psig) by	68.9 to 172.4 kPa (10 to 25 psig)
Catalyst/oil ratio by wt.	4:1 to 20:1
Gasoline yield, vol. % of feed	35 to 50
Coke formation, wt. % of feed	4 to 12
Dry gas formation, wt. %	7 to 11
Conversion of feed to lighter products, vol. %	60 to 90
Coke content of spent catalyst, wt. %	0.25 to 2.3

Regenerator:

Temperature, °C (°F)	566° to 740°C (1050° to 1300°F)
Pressure, kPa (psig)	6.9 to 172.4 kPa (1 to 25 psig)
Coke content of regenerated catalyst, wt. %	0.10 to 0.50

Hydrocarbon cracking deposits a small portion of the feed on the catalyst in the form of coke. Likewise, some sulfur originally present in the feed is deposited on the catalyst. The amount of sulfur varies with the type of feed, rate of recycle, steam stripping rate, type of catalyst, cracking temperature, and other factors.

The amount of hydrocarbon that remains on the spent catalyst as it leaves the cracker is important for safe operation of catalytic cracking units. Essentially all coke-forming compounds are removed in the regenerator by air oxidation. The oxidation reaction is highly exothermic and results in a temperature increase in the regenerator. Excessively high temperatures in the regenerator can be detrimental to the catalyst and also can cause afterburning downstream of the regenerator, which may lead to severe damage of cyclones and auxiliary equipment. Oxidation of coke is accomplished with an amount of air that is insufficient for complete combustion so that only a portion of the carbon is oxidized to carbon dioxide. Usually the volume ratio of carbon dioxide to carbon monoxide is maintained between 1 and 2. The carbon monoxide in the flue gas from the regenerator is then burned to carbon dioxide to recover the remaining energy for steam generation. When CO boilers are used to recover heat in conjunction with the catalytic cracking unit, supplemental fuel is usually provided. The type and amount of fuel used to supplement the carbon monoxide will affect the type and amount of pollutants emitted.

3.4.1.2 Liquid Fuel Burning--

When a refinery process requires a temperature higher than that obtainable from the steam supply or any other available hot stream, direct-fired furnaces are used. These furnaces or fired heaters burn liquid fuels, refinery gases, or commercially available natural gas. The liquid fuels are reduced crude oils, Bunker fuels, vacuum tower bottoms, No. 4 or No. 2 fuel oil, or components comprising these fuels. Operators commonly limit the use of the lighter distillate fuel oils because of their market value and the need for special equipment for safe and efficient combustion.

The number of applications for liquid fuel burning varies among individual refineries, depending on processing complexity. Liquid fuels are used typically in the furnaces for crude oil atmospheric distillation, vacuum distillation, visbreaking, catalytic cracking, coking, thermal cracking, solvent deasphalting, hydrotreating, catalytic reforming, and asphalt stripping. Although refinery furnaces vary in shape and form, with various burner and tube arrangements, they usually consist of two main sections: the radiant section and the convection section. Some unique problems may be associated with certain furnace designs and special fuels such as those of low molecular weight.

3.4.2 Emissions

3.4.2.1 Catalytic Cracker--

Atmospheric emissions from catalytic cracking operations have been measured by several investigators. The primary emissions from catalytic cracking include sulfur oxides, nitrogen oxides, carbon monoxide, carbon dioxide, oxygen, water, nitrogen, hydrocarbons, ammonia, cyanides, and particulates.

Concentrations of sulfur oxides in regenerator flue gases normally range from 150 to 3500 ppm. The concentration of sulfur oxides is a function of the amount of sulfur in the coke present on the catalyst and the amount of air used for regeneration. Because the amount of sulfur present on the spent catalyst in the regenerator is a function of the sulfur level in the crude oils and the processing of the feedstock before it reaches the cracker, the levels of sulfur oxides emitted from the cracker can vary widely. Generally about 10 percent of the total sulfur in the reactor feedstocks remains with the coke on the catalyst. This percentage increases to about 20 percent if the feedstock has been hydrodesulfurized or cracked in another process before being fed to the catalytic cracker.[2]

3.4.2.2 Liquid Fuel Burning--

Potential pollutants from liquid fuel burning include nitrogen oxides, carbon monoxide, particulate, and sulfur dioxide. The formation and emission of pollutants in a furnace depend on the fuel, the operation of the furnace, and the design of the firebox and burners. Because emissions of SO_2 are essentially determined by the sulfur in the fuel, they can be reduced by firing fuels containing lower levels of sulfur but not by redesigning the burners or the firebox.

A high sulfur fuel oil containing 4.0 percent sulfur by weight, when fired in a furnace with 40 percent excess air, could produce a flue gas containing about 0.18 volume percent SO_2 or 1800 ppm by volume. A furnace firing 0.3 percent sulfur fuel oil with 40 percent excess air would discharge 0.015 volume percent SO_2 or 150 ppm by volume in the flue gas.

Either improper atomization of the fuel oil in the burner or provision of insufficient air to burn the fuel oil completely will produce unburned carbon, which is emitted as particulate matter. Excess air is required in all furnaces to assure complete combustion, and thereby minimize carbon monoxide in the flue gas, but high excess air rates reduce thermal efficiency. When fired with liquid fuel oils, refinery furnaces operate with 30 to 50 percent air in excess of that theoretically required. When fired with natural gas, they use only 10 to 25 percent excess air.

3.4.3. Control Measures

3.4.3.1 Catalytic Cracker Units--

Two types of control measures have been applied to control of SO_2 at catalytic cracking operations: desulfurization of the cracker feed and flue gas desulfurization (FGD) of the effluent from the regenerator.

A large research effort has been directed toward development of hydrodesulfurization technology, and many processes applicable to catalytic cracking feedstocks are available. Although hydrodesulfurization does reduce the emission of SO_2, its use is limited for certain feedstocks. The degree of desulfurization required to sufficiently reduce SO_2 emissions involves such severe conditions and such large amounts of hydrogen that complete hydrodesulfurization of feedstocks is not possible.

FGD is based on intimate contact between the flue gas and the liquid droplets of the scrubbing solution. Over the past 15 years, many absorption mediums and contactors have been tried. A system developed by a major oil company consists of a dilute caustic stream in conjunction with a venturi scrubber, which efficiently captures both the sulfur oxides and particulates. The process is in commercial application at four major refineries located in New Jersey, Louisiana, and Texas. The scrubber can be used on regenerators downstream of the waste heat boilers or after heat removal from a high-temperature regenerator, providing adequate pressure drop is available. The technology is offered for license, and reportedly two other commercial installations are planned. No other scrubbing systems are known to be in commercial use on catalytic cracker regenerators, but several FGD's are installed on oil and coal fired boilers.

The mixture of gas and scrubbing solution droplets, after passing through the venturi contactor, passes to a separator where clean flue gases are separated from the scrubbing liquid. The vent gas is discharged to the atmosphere. A purge liquid stream is removed to keep the circulating liquid stream suitable for scrubbing. Purge stream treatment facilities are required prior to effluent disposal.

A commercial-scale FGD system on a cracker regenerator has been in operation since March 1974. The design capacity of this unit is 141.6 m^3/s (300,000 cfm) of flue gas, and the unit has achieved an SO_2 collection efficiency above 95 percent. It has completed a 29-month run with no problems.[3]

To achieve the same levels of pollutant removal on a 12,719 m^3 (80,000 bbl) per day Gulf Coast fluid catalytic cracking unit processing a gas oil containing 3.2 percent sulfur, the FGD system requires an investment only two-thirds of that required for combined hydrodesulfurization of the feed and electrostatic precipitation of the flue gas. Annual operating costs are estimated at half of the costs of hydrodesulfurization and electrostatic precipitation. The benefits to a refiner of products with lower sulfur contents are not considered in these economic comparisons.

3.4.3.2 Liquid Fuel Burning--

The two methods available to reduce SO_2 emissions are desulfurization of the fuel before combustion and FGD.

Reducing the sulfur content of fuel is practiced in some petroleum refineries. To prepare low-sulfur-content liquid fuel acceptable to the home heating market, refiners often desulfurize a distillate stream by the use of hydrogen (hydrodesulfurization). To prepare heavier liquid fuels, marketed with higher sulfur content, the same desulfurized distillate stream is often blended with a residual stream to yield the desired products. Without blending, the high-sulfur-content residual stream would not be marketable. Although the costs vary widely depending on the crude oil type, it is very costly to prepare heavy fuel oils with less than 0.3 percent sulfur by weight from any crude oil; thus most heavy fuel oils produced have sulfur contents of 0.3 percent or higher. Only a small portion of the total production of liquid fuels is burned in the refinery. By the burning of hydrodesulfurized gas, oils and other distillate streams, a refiner can reduce the level of sulfur oxides emitted from the furnaces. At the present time no FGD systems have been utilized in the U.S. to control sulfur dioxide emissions from petroleum refinery heaters and boilers. In Japan, FGD's are used extensively to control SO_2 emissions from oil-fired boilers and heaters.

3.4.4 Emission Limits

3.4.4.1 New Source Performance Standards (NSPS) Limits--

NSPS require control of carbon monoxide and particulate emissions from fluid catalytic cracking unit catalyst regenerators and from FCC incinerator waste heat boilers; there is no limit on SO_2 emissions from such units. In regard to liquid fuel burning, NSPS have been enacted for SO_2 emissions from fossil-fuel-fired boilers of more than 73 MW (250×10^6 Btu/h) heat input rate. The NSPS limit for SO_2 emissions from units of this size that fire liquid fossil fuels is 340 ng/J (0.80 lb/10^6 Btu) heat input. Refinery combustion devices are generally exempt from this NSPS because of their smaller size and/or because they are not used to generate steam.

3.4.4.2 State Implementation Plan (SIP) Limits--

Catalytic crackers--A search of SIP regulations and state laws revealed no SO_2 emission limits that apply specifically to catalytic cracker regenerators.[4] In the absence of source-specific regulations for catalytic cracker regenerators, applicable regulations are those that fall under such general classifications as "other process sources," "noncommercial fuel," or "emissions from fuel combustion operations." The most stringent state and local general process regulations applicable to catalytic cracker regenerators are a New Jersey regulation limiting emissions from noncommercial fuel to 312 ppm SO_2 by volume[5] and a regulation of the Bay Area Air Pollution Control District, San Francisco, California, (Regulation No. 2 3122) limiting concentrations to 300 ppm SO_2 by volume.

Liquid fuel burning--Review of state regulations has shown wide variation in the types of regulations, degree of stringency, and methods of enforcing the limitation. In general SO_2 emissions are limited by a regulation restricting the quantity of SO_2 emitted per unit quantity of heat input or by one limiting the sulfur content of the fuel. In some states the regulations specify maximum allowable ground-level concentrations resulting from emissions. Many states have several forms of regulations, each applying to a different fuel or type of source. Limits on the sulfur content in fuel oils for all purposes range from a low of 0.15 percent to a high of 4.4 percent by weight. Most states differentiate the various grades of oil, allowing higher sulfur contents in residual oils than in distillate oils. The most restrictive regulation of fuel oil sulfur content is about 0.15 percent sulfur; this is a regulation of Clark County, Nevada, which, however, has no petroleum refinery. The most restrictive regulation applicable to an area (New Jersey) in which refineries are operated is 0.2 percent sulfur in No. 2 and lighter commercial fuel oils, and 0.3 percent sulfur in Nos. 4, 5, and 6 residual fuel oils.

3.4.4.3 Achieved in Practice (AIP) Limit--

A commercial-scale FGD unit has demonstrated 95 percent removal of the SO_2 component in exhaust from a catalytic cracker regenerator.[3] The diversity of liquid fuel burning units and of the fuels they burn precludes determining an AIP limit for refinery furnaces. A general AIP limit would be 0.3 weight percent sulfur in fuel.

3.4.5 Determination of LAER

The recommended limitations are based on SIP's and on performance information available in early 1979. It is anticipated that several additional SIP regulations covering these sources will be promulgated and/or modified in 1979 and 1980 and that appreciable new performance data will become available in the near term. Conceivably, some SIP regulations may be more stringent than the LAER suggested herein. Furthermore, performance testing may show that more stringent limits than those suggested are feasible or it may show that the suggested limits are appropriate or that they are not achievable for some specific subcategories. In any case, the basis for determining LAER for many source categories is expected to change frequently. Since LAER is near the vanguard of control technology, a more detailed analysis is particularly necessary when addressing modified or reconstructed facilities subject to the provisions of Section 173 of the Clean Air Act. Emission limitations reasonable for new sources may in some instances be economically or technically unreasonable when applied to modified or reconstructed sources of the same type.

3.4.5.1 Catalytic Cracking Unit--

The San Francisco Bay Area limitation of 300 ppm is the most stringent regulation adopted to date. Compliance with this regulation can be achieved with FGD on even the highest concentration of SO_2 anticipated in regenerator flue gases. Additionally, the period of operation between turnarounds on an FGD system has been demonstrated to be as long as the period between turnarounds on catalytic cracker units, or longer. An FGD system can be used on a waste gas stream from a high-temperature regenerator or a CO boiler.

An alternative control measure applicable to most catalytic cracker feedstocks is hydrodesulfurization or the processing of low-sulfur feed stocks. Application of this process is limited, however, because the degree of desulfurization needed to conform with strict emission regulations is extremely high relative to normal feedstock desulfurization requirements.

Therefore, it is concluded that the LAER for SO_2 emissions from catalytic cracker regenerators is 300 ppm or a 95 percent by volume reduction of the uncontrolled concentration from the source, whichever is less stringent; this degree of control may be achieved by application of FGD or by other equally effective methods.

3.4.5.2 Liquid Fuel Burning--

Although some industries are installing FGD systems on industrial-size boilers and furnaces, none are yet installed in petroleum refineries. A petroleum refiner's primary business is production of marketable fuels that meet Federal, state, and local regulations on sulfur or SO_2 content. Because he burns for for his own use only 2 to 6 percent of the fuel produced, the refiner may be in a position to achieve a low emission rate by preparing and burning low-sulfur fuels. Most other industries, lacking the capability to produce their own fuel and to ensure a low-sulfur fuel supply, may have to attain LAER by alternative means.

Alternatively, refiners are also in a better position than their customers to install an FGD system and burn high sulfur residual oil. The furnaces at refineries are located near the process they serve and therefore are sometimes scattered throughout the refinery property. The distance between furnaces could require that separate systems be installed if FGD were chosen for reduction of SO_2 emissions. New refineries can generally incorporate plans to install fuel oil desulfurization equipment on a single stream, produce low-sulfur fuel oil, and overcome the constraints involved in FGD application.

In summary, SO_2 emission from liquid fuel burning is directly related to the sulfur content of the fuel. The LAER for liquid fuel burning is that SO_2 emission level equivalent to the use of fuel having 0.3 weight percent sulfur, corresponding to approximately 150 ppmv SO_2.

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3.5 MAJOR SOURCE CATEGORY: FABRIC COATING--VOLATILE ORGANIC COMPOUND (VOC) EMISSIONS

3.5.1 Process Description

Fabric coating involves the coating of a textile substrate to impart properties that are not initially present, such as strength, stability, water or acid repellency, or appearance.[1] The fabric coating industry is diverse, with wide variations in both products and plant sizes. The coated textiles are used in industrial and electrical tapes, tire cord, utility meter seals, imitation leathers, tarpaulins, shoe materials, upholstery fabrics, and rubber-coated fabrics.

Coating solutions may be either aqueous or organic based. The latter produces organic emissions. It is estimated that 36 Gg/h (80 x 10^6 lb/yr) of VOC is emitted in the United States by the vinyl-coated fabric segment of the industry.[1]

Figure 3.5-1 shows a typical fabric coating operation. Milling and mixing of coatings are primarily restricted to coatings containing rubber, and emissions are not considered significant.

Fabric is usually coated with a knife or a roller coater. Both are spreading devices for high-speed application of coatings to flat surfaces; the operations are very similar to the paper coating techniques shown in Section 3.18, Figures 3.18-2 and 3.18-3.

In knife coating, probably the least expensive method, the substrate is held flat by a roller and is drawn beneath a knife that spreads the viscous coating evenly over the full width of the fabric. Knife coating may not be appropriate with materials such as certain unstable knit goods or in applications requiring great precision in the coating thickness.

In roller coating, the coating material is applied to moving fabric, in a direction opposite to the movement of the substrate,

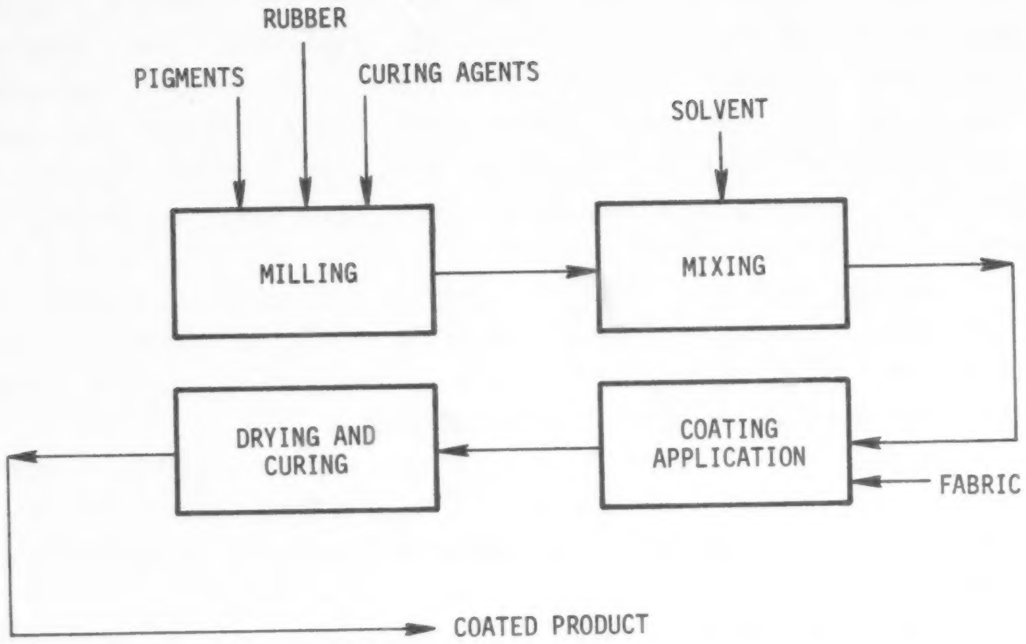
RUBBER
PIGMENTS
CURING AGENTS
SOLVENT
MILLING
MIXING
DRYING AND CURING
COATING APPLICATION
FABRIC
COATED PRODUCT

Figure 3.5-1. Typical fabric coating operation.

by hard rubber or steel rolls. Roller coaters apply a coating of constant thickness without regard to fabric irregularities.

Rotogravure printing is widely used in vinyl coating of fabrics and is a large source of solvent emissions. Rotogravure printing involves a roll coating technique in which the pattern to be printed is etched on the coating roll with thousands of tiny recessed dots. The recessed dots pick up ink from a reservoir and transfer it to the fabric surface.

After being coated, the fabric is sent to drying ovens. Typical drying ovens process fabric continuously, operating with a web or conveyor feed system. Ovens can be enclosed or semi-enclosed; depending on size, they exhaust from a few thousand to tens of thousands of cubic feet per minute of air. Newer installations are reported to operate with exhaust concentrations up to 40 percent of the lower explosive limit (LEL). The oven heat accelerates evaporation of the solvent and can produce chemical changes within the coating solids to give desired properties to the product. Many operators control evaporation rates to give desired properties to the coated fabric. High air velocities distribute heat uniformly over the fabric surface, facilitate heat transfer to the coating and substrate (by minimizing the laminar zone next to the the coated surfaces), and remove evaporated solvents from the oven at a rate that will prevent their buildup to explosive levels.

3.5.2 Emission of Pollutants

The coating line, consisting of the coating application area and drying oven, is the largest source of solvent emissions in a fabric coating plant. It is also the most readily controllable. The coater and the oven are both considered significant emitting facilities. Some coating plants report that over 70 percent of the solvents used within the plant are emitted from the coating line. Other plants, especially those using vinyl coatings, report that only 40 to 60 percent of the solvents purchased are emitted from the coating line. The remaining solvents are lost as fugitive emissions from other stages of processing and cleanup. Control techniques for fugitive sources include tightly fitting covers for open tanks, collection hoods for areas where solvent is used for cleanup, and closed containers for solvent wiping cloths.

Solvent emissions from the coating applicator account for 25 to 35 percent of all solvent emitted from a coating line. This solvent may be collected by totally enclosing the applicator in a small room or booth and exhausting the booth to a control device. Another method is to cover the applicator with a hood that can collect most of the solvent emissions. Solvent emissions from the ovens account for 65 to 75 percent of all solvent emitted from a coating line. In most ovens, almost all the solvent emissions are captured and vented with exhaust gases. On some coating lines, emissions from the coating applicator hood are ducted to the oven and included with the oven exhaust.

3.5.3 Control Measures

Although few fabric coating facilities have elected to control organic emissions, several technically feasible control systems are available. These are carbon adsorption and incineration. Another approach to reducing organic emissions is to switch to coatings with lower organic solvent content, such as aqueous emulsion coatings.

As in the paper coating industry (Section 3.18), carbon adsorption systems on fabric coating lines have been shown to be 97 to 98 percent efficient in controlling organic solvent vapors that are drawn into the carbon bed.[2-4] Control efficiencies are limited somewhat by the inability to capture all emissions from the coating application area. In paper coating operations, recovery of the solvent introduced to the coating line has been documented in the range of 96 percent. The similarity between fabric and paper coating lines suggests that this efficiency is also achievable in fabric coating operations.[1,5] The RACT document pertaining to fabric coating suggests a minimum of 90 percent efficiency for collection of coating line emissions.[1]

Both catalytic incinerators and thermal incinerators (afterburners) can destroy 95 to 99 percent of the organic emissions introduced to them. As stated earlier, the overall facility control is dependent on the solvent emission capture efficiency. Although the use of afterburners in fabric coating plants has not been documented, afterburner efficiencies of 98 to 99 percent have been obtained across the device.[6] The same efficiencies should also be achievable in fabric coating operations.

Although incineration consumes energy, recovery of heat can eliminate or minimize this disadvantage. Fuel costs can also be reduced by increasing the organic level in exhaust gases, i.e., by reducing dilution air.

As shown in Table 3.18-1 (paper coating), an overall reduction of 80 to 100 percent can be attained through the use of coatings with inherently low levels of organic solvents. The degree of reduction depends on the organic solvent contents of the coating used originally and the new coating. No industry contacts reported information from plants using low-solvent coatings. Although some plants have converted to use of low-solvent coatings, this action cannot be considered a universally applicable control measure. Coating line operations and fabric specifications vary widely.

Several considerations affect the technical and economic feasibility of organic emission control in the fabric coating industry. Although the larger facilities may specialize in a specific product, many plants produce a variety of products or operate under contract to coat products to a customer's specifications. The latter operators, often called "commission coaters," must use a variety of coating formulations to comply with

At any time during the operation the arc may be lost, for such reasons as shutoff due to a preset "demand limiter," mechanical failure, or faulty positioning of the electrodes. If the arc can be reestablished quickly, this loss has slight effect on emission level, since the roof is closed and the melt is hot. If the bath must cool, however, striking the arc again will vaporize metal and cause a surge of very high particulate. Minimizing arc interruptions is the best means of preventing such emissions.

Tapping iron and steel is done with the power off, the electrodes lifted, and the furnace tilted. During the pouring of iron or steel, very fine particulate escapes as sparks or fume along the flowing stream of hot metal. These emissions are negligible in gray iron production, but perhaps because of the much higher temperatures needed for steel [200°C or (390°F)], they can be at least as severe as those during charging. Treatments such as deoxidation or special alloying are often done while the molten metal is poured or is in the ladle and can cause violent emissions of short duration.

3.3.3. Control Measures

Control of air pollution at an iron or steel foundry is a function of the efficiency of two operations:

1. Capture and containment of particulate-laden gases as they are generated at the furnace or at the ladle.
2. Treatment of the captured, particulate-laden gases in a control system to remove the particulate material.

Methods and equipment for capture of pollutants are described in Reference 2. Important among these methods is the use of large canopy hoods, which are positioned over the open furnace and over an open ladle during charging and during tapping/alloying in the ladle. While the lid is on the furnace, either a roof or side-draft hood on the furnace roof or a direct furnace evacuation system on the furnace roof is used. The canopy hoods must be located precisely so as to maximize pollutant capture and minimize the total amount of air pulled into the hood with minimal interference to operation of the overhead crane, charging buckets, and other equipment. Some means of eliminating crosscurrents of air, such as a shroud enclosure around part of the furnace, improves the efficiency of the canopy hoods.

unless the solvent content of the coating used is no more than 265 g/liter (2.2 lb/gal) of coating minus water.

In the definition of LAER for surface coating emissions, it is not appropriate to exempt solvents based on their reactivity. Recent research has indicated that substituting low-reactivity solvents for higher-reactivity solvents may improve photochemical oxidant air quality in one city while worsening it in downwind regions.[10] Accordingly, EPA has adopted a policy emphasizing the need for "positive reduction techniques" rather than substitution of compounds.[7]

Emission controls achieved in practice for fabric coating exceed regulatory requirements by a wide margin. Therefore, it is concluded that LAER for fabric coating is a function of controls achieved in practice rather than controls required by current regulations.

3.5.5 Determination of LAER

The recommended limitations are based on SIP's and on performance information available in early 1979. It is anticipated that several additional SIP regulations covering these sources will be promulgated and/or modifed in 1979 and 1980 and that appreciable new performance data will become available in the near term. Conceivably, some SIP regulations may be more stringent than the LAER suggested herein. Furthermore, performance testing may show that more stringent limits than those suggested are feasible or it may show that the suggested limits are appropriate or that they are not achievable for some specific subcategories. In any case, the basis for determining LAER for many source categories is expected to change frequently. Since LAER is near the vanguard of control technology, a more detailed analysis is particularly necessary when addressing modified or reconstructed facilities subject to the provisions of Section 173 of the Clean Air Act. Emission limitations reasonable for new sources may in some instances be economically or technically unreasonable when applied to modified or reconstructed sources of the same type.

Control efficiencies greater than 95 percent across the control device have been documented on fabric coating operations using thermal or catalytic incineration or carbon adsorption systems.[2,3,4,6] At least 90 percent of the VOC emissions from fabric coating can be sent to a control device that yields an overall control efficiency of 85 percent, which is equivalent to the uncontrolled emissions from a low-solvent coating containing 310 g of solvent/liter (2.6 lb/gal) of coating minus water. The following shows this derivation:[11]

Assuming a typical coating contains 22 percent solids,

100 gallons of coating contains 22 gal solids

and 78 gal solvent

Reducing the solvent emitted yields: (78) - [0.85 (78)] = 11.7 gal permitted

Assuming a solvent density of 7.36 lb/gal, 11.7 gal = 86.1 lb solvent

Equivalent coating required = 86.1 lb solvent/(22 + 11.7) gal of coating minus water

= 2.6 lb solvent/gal coating minus water

= 310 g solvent/liter coating minus water

Although conversion to a waterborne or higher-solids coating will significantly reduce VOC emissions, the 310 g/liter (2.6 lb/gal) limitation may not be achievable, in which case control of part of the VOC emissions is still recommended. The recommended LAER limitation for vinyl coating is 370 g solvent/liter (3.0 lb/gal) minus water, based on solids content of 15 percent and a solvent density of 826 g solvent/liter (6.7 lb/gal). Complete control of VOC emissions using add-on control devices providing at least 85 percent overall plant control is also acceptable.

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3.6 MAJOR SOURCE CATEGORY: LARGE INDUSTRIAL BOILERS--PARTICULATE SULFUR DIOXIDE, AND NITROGEN OXIDE EMISSIONS

3.6.1 Process Description

Industrial boilers are fired with coal, natural gas, oil, and industrial wastes. The resulting heat of combustion is then used to produce steam in the boilers. Liquids other than water may be heated in the boiler for use in subsequent industrial processes. The hot flue gases, after producing steam in the boiler, pass through an economizer and sometimes an air heater and are finally discharged through a stack.

This section deals with coal-fired boilers in the heat input range of 58 to 175 MW (200 to 600 x 10^6 Btu/h), including stokers in the range of 88 to 117 MW (300 to 400 x 10^6 Btu/h); and with oil-fired boilers in the range of 73 to 102 MW (250 to 350 x 10^6 Btu/h).

3.6.1.1 Pulverized-Coal-Fired Boilers--

For combustion in a pulverized-coal-fired boiler, coal is pulverized so that at least 70 percent passes through a 200-mesh sieve. This finely ground coal is conveyed pneumatically to a burner located in the furnace. The system operates as a continuous process; within specified design limitations, the coal feed can be varied as required by boiler load. Figure 3.6-1 depicts a pulverized-coal-fired boiler system.

A small portion of the air required for combustion (15 to 20 percent in current installations) is used to transport the coal to the burner. This is known as primary combustion air. The primary air is also used to dry the coal in the pulverizer. The remainder of the combustion air (80 to 85 percent) is introduced at the burner and is known as secondary air. The control system regulating the flow of both coal and primary air is so designed that a predetermined air/coal ratio is maintained for any given load.[1]

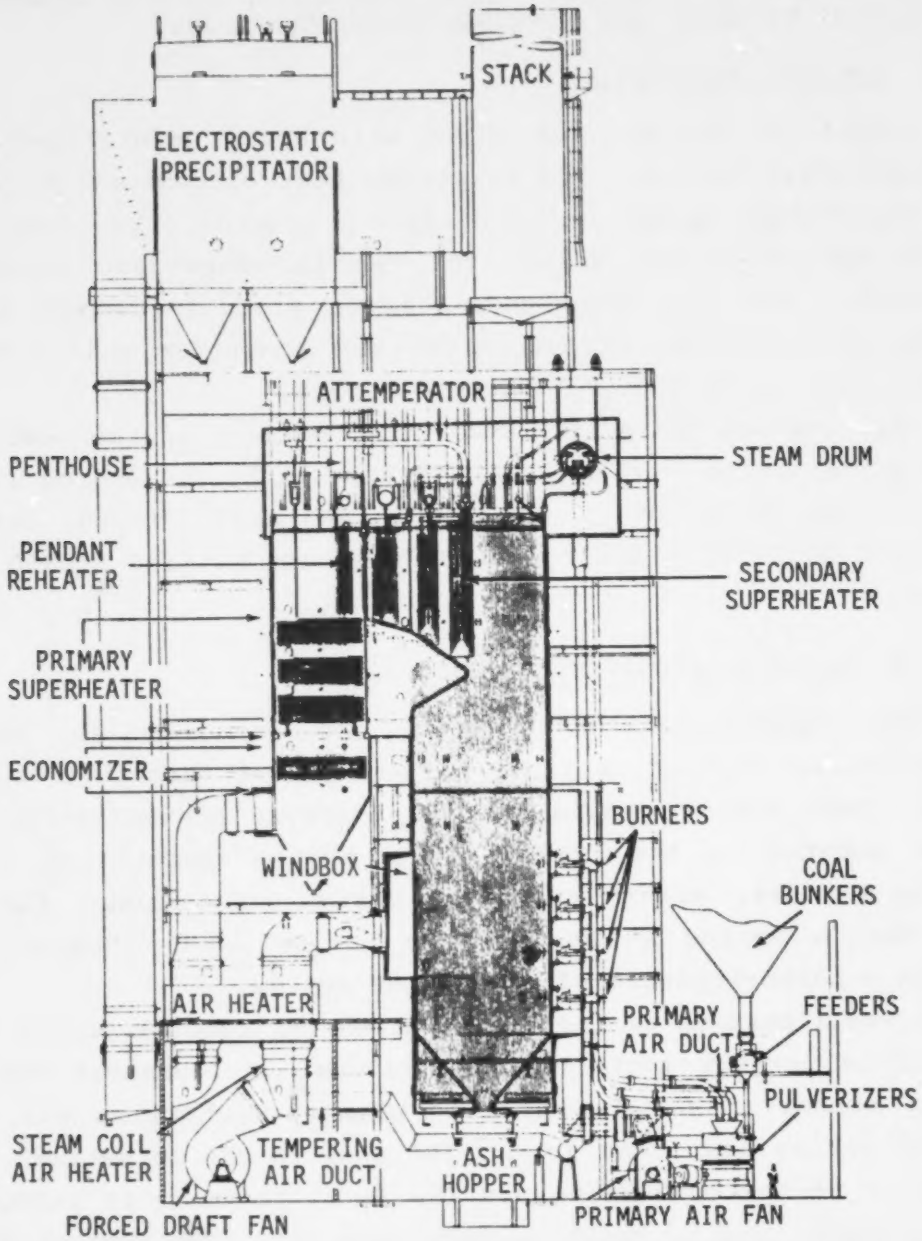

STACK
ELECTROSTATIC PRECIPITATOR
ATTEMPERATOR
PENTHOUSE
STEAM DRUM
PENDANT REHEATER
SECONDARY SUPERHEATER
PRIMARY SUPERHEATER
ECONOMIZER
BURNERS
WINDBOX
COAL BUNKERS
AIR HEATER
PRIMARY AIR DUCT
FEEDERS
PULVERIZERS
STEAM COIL AIR HEATER
TEMPERING AIR DUCT
ASH HOPPER
FORCED DRAFT FAN
PRIMARY AIR FAN

Figure 3.6-1. Radiant boiler for pulverized coal firing.
(The Babcock & Wilcox Co.)

Burners are characterized by firing position, i.e., wall-fired or tangential.[1] Arrangements for the introduction of primary, secondary, and, in some cases, tertiary air vary with burner manufacturers. One manufacturer uses an adjustable burner that can be tilted upward or downward to control the furnace outlet temperature so that steam temperature can be regulated over a wide range.

Pulverized-coal-fired boilers may be designed as either wet or dry bottom units. In a wet bottom furnace, the temperature is maintained above the ash fusion temperature and the ash is melted so that it can be removed from the furnace as a liquid. In a dry bottom furnace, the temperature is maintained below the ash fusion temperature so that the ash will not fuse.

3.6.1.2 Stoker-Fired Boilers--

Stoker-fired boilers are used in the small to medium size ranges from 9 to 117 MW (30 to 400 x 10^6 Btu/h). The stokers are designed to feed coal onto a grate in the furnace and to remove the ash residue. Higher rates of combustion are possible, and the continuous process of stoker firing permits good control and high efficiency. Stokers are often preferred over pulverizers because of their greater operating range (i.e., operation at low loads) and lower power requirements, and because they can burn a variety of solid fuels.

The grate area required for a given stoker type and capacity is determined from rates established by experience. Table 3.6-1 lists maximum recommended coal burning rates for three types of stokers, which are discussed in the following paragraphs.

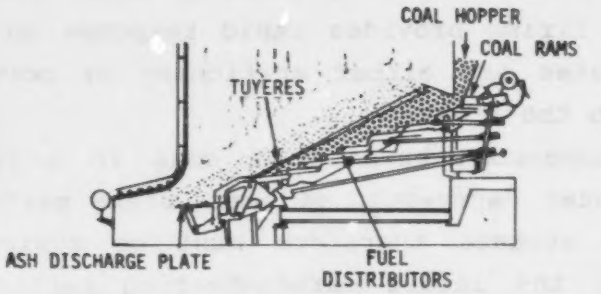
TABLE 3.6-1. MAXIMUM ALLOWABLE COAL BURNING RATES FOR THREE TYPES OF STOKERS[1]

Type of stoker	Coal burning rate	
	MW/m^2	$(Btu/ft^2 \cdot h)$
Multiple-retort underfeed stokers	1.89	(600,000)
Chain- or traveling-grate stokers	1.58	(500,000)
Spreader stokers	2.36	(750,000)

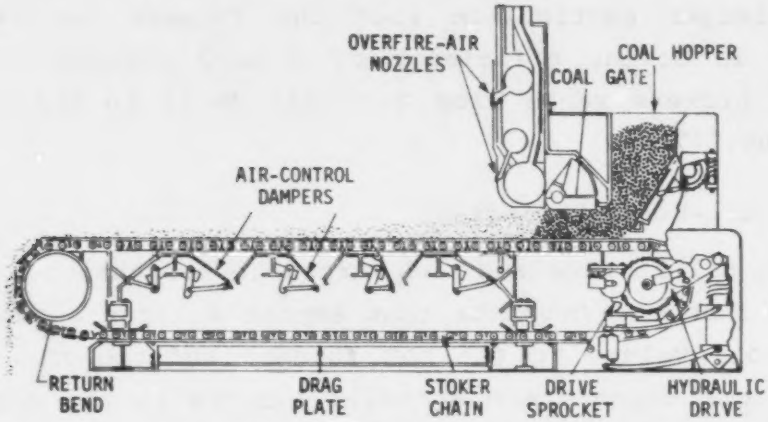
Multiple-retort underfeed stokers--In a multiple-retort, rear-end-cleaning stoker the retort and grate are inclined 20 to 25 degrees. These units usually consist of several inclined retorts side by side, with rows of tuyères between each retort (Figure 3.6-2a). Coal is worked from the front hopper to the rear ash-discharge mechanism by pushers. The forced-air system is zoned beneath the grates by means of air dampers, and combustion control is fully modulated. In larger furnaces the walls are water-cooled, as are the grate surfaces in some units. Use of multiple-retort underfeed stokers is declining. Capacities generally range from 7 to 146 MW (25 to 500 x 10^6 Btu/h).[1]

Chain-grate or traveling-grate stokers--A chain-grate (Figure 3.6-2b) or traveling-grate unit consists essentially of grate sections that move from the front to the rear, carrying coal from the hopper in front into the combustion zone. The fuel bed moves progressively to the rear, where the ash is continuously discharged. Modern units have zone-controlled forced draft. Complete combustion-control systems are used, and overfire air, especially in the front wall, aids combustion of the volatiles in the fuel. Capacities range from 6 to 88 MW (20 to 300 x 10^6 Btu/h) heat input.[1]

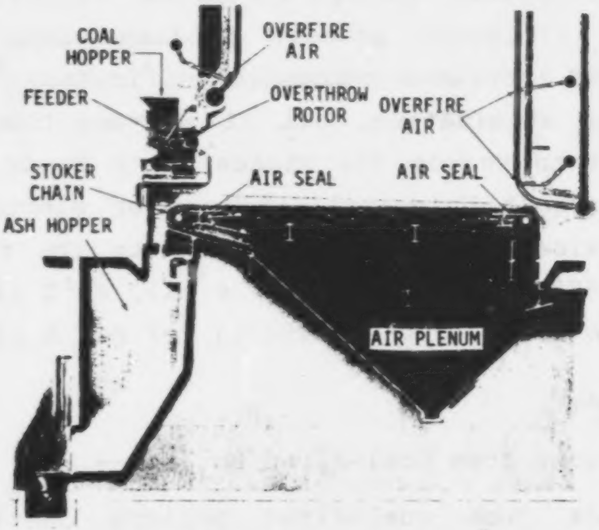
Spreader stokers--The spreader stoker combines suspension and fuel bed firing by the stoker mechanism, which throws coal into the furnace over the fire with a uniform spreading action (Figure 3.6-2c). Because coal is burned partly in suspension and


COAL HOPPER
COAL RAMS
TUYERES
ASH DISCHARGE PLATE
FUEL
DISTRIBUTORS

a. Multiple-retort underfeed stoker.[1]


OVERFIRE-AIR
NOZZLES
COAL HOPPER
COAL GATE
AIR-CONTROL
DAMPERS
RETURN
BEND
DRAG
PLATE
STOKER
CHAIN
DRIVE
SPROCKET
HYDRAULIC
DRIVE

b. Traveling-grate spreader stoker with front ash discharge.[1]


COAL
HOPPER
OVERFIRE
AIR
FEEDER
OVERTHROW
ROTOR
OVERFIRE
AIR
STOKER
CHAIN
AIR SEAL
AIR SEAL
ASH HOPPER
AIR PLENUM

c. Chain-grate stoker.[1]

Figure 3.6-2. Types of stokers.

partly on the grate, the coal forms a thin, fast-burning bed. This method of firing provides rapid response to load fluctuations. The grates are either stationary or move continuously from the rear to the front.

Partial suspension burning of coal in a spreader stoker results in greater carry-over of particulate matter in the flue gas. Spreader stokers therefore must be equipped with dust collectors, and the larger carbon-bearing particles are often recirculated to the furnace for further burning. Recirculation of the larger particulate into the furnace can result in an increase in boiler efficiency of 2 to 3 percent. Capacity of spreader stokers range from 2 to 146 MW (6 to 500 x 10^6 Btu/h) heat input.[1,2]

3.6.1.3 Oil-Fired Boilers--

Fuel oil is atomized and burned in suspension. Atomization produces fine oil droplets that expose a large surface area per unit of oil volume to the hot furnace and promotes combustion.

The oil burners are normally located in the vertical walls of the furnace, as shown in Figure 3.6-3. Before the oil reaches the burner it is passed through a strainer or filter that removes sludge. This filtering process prolongs pump life, reduces burner wear, and increases combustion efficiency.[3]

For proper atomization, oil of a grade heavier than No. 2 must be heated to reduce its viscosity to 26 to 30 x 10^{-6} m^2/s (130 to 150 Saybolt Universal). Steam or electric heaters are required to raise the oil temperature to the required degree: approximately 57°C (135°F) for No. 4 oil, 85°C (185°F) for No. 5 oil, and 93° to 121°C (200° to 250°F) for No. 6 oil.[2]

3.6.2 Emissions

3.6.2.1 Emissions from Coal-Fired Boilers--

Flue gases from coal-fired boilers contain particulate matter and gaseous products of combustion, including oxides of sulfur and nitrogen.

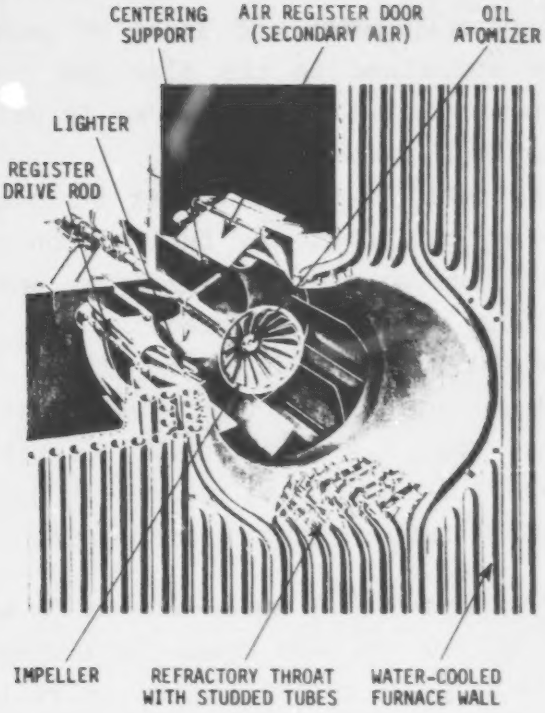

CENTERING SUPPORT
AIR REGISTER DOOR (SECONDARY AIR)
OIL ATOMIZER
LIGHTER
REGISTER DRIVE ROD
IMPELLER
REFRACTORY THROAT WITH STUDDED TUBES
WATER-COOLED FURNACE WALL

Figure 3.6-3. Oil firing burner with water-cooled throat.[2]

Particulates--The quantity of uncontrolled particulate emissions depends primarily on the type of combustion unit, the ash content of the coal, the fuel rate, and the degree of fly ash reinjection. On stoker-fired units, the grate heat-release rate and coal size also affect emissions.

When pulverized coal is burned, nearly all the ash particles are formed in suspension and about 80 percent of the ash leaves the furnace entrained in the flue gas. In a slag-type or wet bottom furnace, however, as much as 50 percent of the ash may be retained in the furnace.

In a properly operated stoker burning coal, the passage of air and the agitation of the fuel bed on the grate serve to keep ash accumulations more or less porous, and the ash is discharged to an ashpit in fairly large pieces.

With a spreader stoker, some of the fuel is burned in suspension and a considerable quantity of ash particles, containing some unburned fuel, is consequently carried over with the gases. This material is usually collected in hoppers and may be reinjected into the furnace for further burning.

Sulfur oxides--In a coal-fired furnace, about 90 to 95 percent of sulfur in the coal is converted to sulfur oxides (SO_x).[4] The balance of the sulfur is emitted in the fly ash or combines with the slag or ash in the furnace and is removed with them. Sulfur dioxide is the principal oxide of sulfur; only 2 to 3 percent of the sulfur content of the coal is emitted as sulfur trioxide. Rates of sulfur oxides emissions depend on the sulfur content of the coal and not on the type of furnace.

Nitrogen oxides--Emissions of nitrogen oxides (NO_x) are caused by high-temperature reaction of atmospheric nitrogen and oxygen in the combustion zone (called "thermal NO_x") and also by partial combustion of nitrogenous compounds in the fuel ("fuel nitrogen"). The important factors that affect NO_x production are flame and furnace temperature, residence time of combustion gases at the flame temperature, rate of cooling of the gases, and amount of excess air in the flame.

Emission factors for coal-fired boilers are presented in Table 3.6-2.[5]

3.6.2.2 Emissions from Oil-Fired Boilers--

Emissions from fuel oil combustion depend on the grade and composition of the fuel, the type and size of the boiler, the firing and loading practices, and the level of equipment maintenance. Table 3.6-3 presents emission factors for fuel oil combustion in industrial boilers without control equipment.[5] The emission factors for industrial boilers are grouped into distillate and residual oil categories because the combustion of each produces significantly different emissions of particulates, SO_x, and NO_x.

Particulates--Particulate emissions are most dependent on the grade of fuel fired. The lighter distillate oils cause significantly lower particulate formation than do the heavier residual oils. In boilers firing Grade 6 oil, particulate emissions generally can be considered as a function of the sulfur content of the oil. This is because Grade 6 oil, whether refined from naturally occurring low-sulfur crude oil or desulfurized by one of several processes currently in practice, has substantially lower viscosity than other grades, and also lower asphaltene, ash, and sulfur contents, all of which lead to better atomization and cleaner combustion.[5]

Boiler load can affect particulate emissions in units firing Grade 6 oil. At low loads particulate emissions may be reduced by as much as 60 percent. No significant particulate reductions at low loads have been noted in boilers firing any of the lighter grades.

Nitrogen oxides--Emissions of NO_x formed from fuel nitrogen are primarily a function of the nitrogen content of the fuel and the available oxygen. Emissions of thermal NO_x are largely a

TABLE 3.6-2. EMISSION FACTORS FOR BITUMINOUS-COAL-FIRED INDUSTRIAL BOILERS WITHOUT CONTROL EQUIPMENT[5]

Furnace capacity, MW (10^6 Btu/h) heat input	Particulates,[a] kg/Mt (lb/ton) coal burned	Sulfur oxides,[b] kg/Mt (lb/ton) coal burned	Nitrogen oxides, kg/Mt (lb/ton) coal burned
Greater than 29 (100)			
Pulverized			
Wet bottom	6.5A (13A)[c]	19S (38S)	15 (30)
Dry bottom	8.5A (17A)	19S (38S)	9 (18)
Spreader stoker[d]	6.5A (13A)[e]	19S (38S)	7.5 (15)

[a] The letter A on all units indicates that the weight percentage of ash in the coal should be multiplied by the value given. Example: If the factor is 8 and the ash content is 10 percent, the particulate emissions before the control equipment would be 10 times 8, or 80 kg of particulate per Mt of coal (10 times 16, or 160 pounds of particulate per Mt of coal).

[b] S equals the sulfur content (see footnote a above).

[c] Without fly-ash reinjection.

[d] For all other stokers use 5A for particulate emission factor. Emission factor data for stokers with capacities greater than 29 MW are not documented.

[e] Without fly-ash reinjection. With fly-ash reinjection from first-staged collector, use 20A.

TABLE 3.6-3. EMISSION FACTORS FOR FUEL OIL COMBUSTION[5]

Pollutant	Residual oil, kg/kl (lb/10^3 gal)	Distillate oil, kg/kl (lb/10^3 gal)
Particulate	a	0.25 (2)
Sulfur dioxide[b]	19.25 (158.65)	17.2S (143.68)
Nitrogen oxides (total as NO_2)	7.5[c] (60)[c]	2.8 (22)

[a] Particulate emission factors for residual oil combustion are best described, on the average, as a function of fuel oil grade and sulfur content, as shown below.

Grade 6 oil: kg/kl = 1.25(S) + 0.38
[lb/10^3 gal = 10(S) + 3]

where: S is the percentage, by weight, of sulfur in the oil

Grade 5 oil: 1.25 kg/kl (10 lb/10^3 gal)

Grade 4 oil: 0.88 kg/kl (7 lb/10^3 gal)

[b] S is the percentage, by weight, of sulfur in the oil.

[c] Nitrogen oxides emissions from residual oil combustion in industrial and commercial boilers are strongly dependent on the fuel nitrogen content and can be estimated for accurately by the following empirical relationship:

$$\text{kg } NO_2/\text{kl} = 2.75 + 50(N)^2,$$

$$[\text{lb } NO_2/10^3 \text{ gal} = 22 + 400(N)^2]$$

where: N is the percentage, by weight, of nitrogen in the oil. Note: For residual oils having high (>0.5%, by weight) nitrogen contents, one should use 15 kg NO_2/kl (120 lb $NO_2/10^3$ gal) as an emission factor.

function of peak flame temperature and available oxygen, factors that depend on boiler size, firing configuration, and operation practices. Fuel NO_x are the predominant NO_x emissions in boilers firing residual oil. Thermal NO_x emissions predominate in units firing distillate oils, primarily because the nitrogen content of these lighter oils is negligible.

3.6.3 Control Measures

3.6.3.1 Particulate--

Problems of ash removal and disposal are significant, principally where solid fuels are burned. Fuel oil contains little ash, and any ash formation primarily affects the furnace and boiler interiors. Mechanical dust collectors are used occasionally.

With the early methods of burning coal on grates with natural draft, most of the coal ash remained on the grate and was ultimately discharged into a hopper for disposal. With the newer boilers, such as the spreader stoker and the pulverized-coal-fired boilers, part or all of the burning occurs in suspension, leading to greater carry-over of particulate matter in the flue gas.

Achieving a low emission rate requires some form of particulate control equipment to remove the fly ash from flue gases of units that burn solid fuels. In addition, careful operation and use of the fuel specified for the boiler are required to minimize visible emissions. The commercially available high-efficiency particulate removal equipment includes electrostatic precipitators, fabric filters, and wet scrubbers.[6]

Electrostatic precipitators--Precipitators are the most widely used particulate control device on pulverized-coal-fired boilers. Electrostatic precipitators impart an electric charge to the particles to be collected and then propel the charged particles by electrostatic force to the collecting electrodes.

Collection efficiency of an electrostatic precipitator depends on the time of particle exposure to the electrostatic field, the strength of the field, and the resistivity of the dust particle. Efficiency above 99 percent can be achieved when the unit is properly designed. Table 3.6-4 presents selected operating and design data for a spreader-stoker coal-fired boiler.[6]

Fabric filters--These devices are being used increasingly on coal-fired stokers, but to a lesser extent on those burning pulverized coal. Use of fabric filters is favored when sulfur content of the coal is very low and when carbon content of the particulate is high (as in spreader stokers).

Fabric filters trap dust particles by impingement on the fine fibers of the fabric. As the collection of dust continues, an accumulation of dust particles adheres to the fabric surface, forming a highly efficient filter cake. The fabric filter achieves maximum efficiency during this period of dust buildup. After a fixed operating period, which depends on the pressure drop, the bags are cleaned by passage of a reverse flow of air or by mechanical vibration. Filtering efficiency is slightly lower after cleaning until the collected dust again forms a filter cake.

The fabric filter can be applied to any boiler for which dry collection is desired and maximum temperatures are lower than about 288°C (550°F).[7] Coated fiberglass filters are generally used at the upper temperature limit. Efficiencies greater than 99 percent can be achieved, as shown in Table 3.6-5.

Wet scrubbers--Wet scrubbers remove dust from a gas stream by collecting it with a suitable liquid. A good wet scrubber can effect intimate contact between the gas stream and liquid for the purpose of transferring suspended particulate matter from the gas to the liquid. Collection efficiency, dust-particle size, and pressure drop are closely related in the operation of a wet scrubber. The required operating pressure drop varies inversely with dust-particle size at a given collection efficiency; or, for

TABLE 3.6-4. EXAMPLE OF AN ESP APPLICATION ON A COAL-FIRED BOILER[6]

Plant name	Heskett Unit 1
Location	Mandan, North Dakota
Boiler capacity	25 MW (output); about 75 MW input
Boiler type	Spreader stoker
Fuel type	Coal, lignite
Sulfur content	0.3 to 1.4 %
Ash content	6.7 %
Moisture content	36.1 %
Flue Gas	
Temperature	214°C (418°F)
Volume	180,000 Nm^3/h (189,000 acfm)
Velocity in ESP	1.16 m/s (3.8 ft/s)
Collecting surface[a]	6180 m^2 (66,500 ft^2)
Inlet loading	5.7 to 9.4 g/m^3 (2.5 to 4.1 gr/ft^3)
Outlet loading	0.023 g/m^3 (0.01 gr/ft^3)
Efficiency	99.68% (designed for 99.45%)

[a] Specific collection area is 1154 $m^2/1000\ m^3/min$ (352 $ft^2/1000$ acfm).

TABLE 3.6-5. EXAMPLE BAGHOUSE DESIGN PARAMETERS AND OVERALL EFFICIENCY[6]

Plant name	Nucla Station
Location	Nucla, Colorado
Boiler type	Spreader stoker
Boiler capacity	12.65 MW (one of three boilers); about 40 MW input
Gas flow rate	146,000 m^3/h (86,240 acfm)
Compartments	6
Fabric	Fiberglass with graphite finish
Air-to-cloth ratio, 6 compartments	51 m^3/h per m^2 (2.8 $acfm/ft^2$)
Air-to-cloth ratio, 5 compartments (cleaning or maintenance on one compartment)	61 m^3/h per m^2 (3.35 $acfm/ft^2$)
Pressure drop (normal)	1120 Pa (4.5 in. H_2O)
Pressure drop (cleaning)	Up to 1490 Pa (6 in. H_2O)

Load, MW	Overall efficiency, %	Total particulate emission, ng/J ($lb/10^6$ Btu)
6	99.98	3.0 (0.007)
11	99.97	8.6 (0.02)
12	99.92	17.2 (0.04)

a given dust-particle size, collection efficiency increases as operating pressure drop increases. Although scrubbers are not widely used on boilers, they can achieve collection efficiencies in the range of 80 to 99 percent, as shown in Table 3.6-6.[6]

3.6.3.2 Sulfur Oxides--

Sulfur oxides can be controlled by burning low-sulfur fuel (naturally occurring or pretreated for sulfur removal) or by removing the sulfur oxides from the combustion gases before they are released (flue gas desulfurization, FGD). The pretreating techniques include physical and chemical coal cleaning, coal liquefaction and coal gasification. Physical coal cleaning is limited to removal of pyritic sulfur and can achieve up to 50 percent SO_2 removal. Chemical coal cleaning, gasification, and liquefaction are not in commercial operation at this time. FGD technologies include:

1. Injection of materials such as limestone or dolomite into the furnace.
2. Wet scrubbing of flue gases.
3. Use of dry sorbent systems.

Of these processes, only wet scrubbing is widely used with industrial boilers.

Wet scrubbing of flue gases--Wet scrubbing FGD systems applied on coal-fired industrial boilers in the United States include lime or limestone scrubbing, the dilute or concentrated double alkali process, and scrubbing with sodium carbonate or sodium hydroxide solutions.[8] In these systems, flue gases contact the scrubbing solution after fly ash is removed in an ESP or prescrubber. Sulfur dioxide reacts with the slurry in a scrubber-absorber and forms large quantities of sludge. The sludge is separated and disposed of, while the scrubbing solution is recirculated with the makeup slurry. These FGD units have achieved efficiencies above 90 percent, as shown in Table 3.6-7, but long-term monitoring data are lacking. Many other sulfur oxide removal systems are used on large utility boilers and on industrial oil-fired boilers.

TABLE 3.6-6. EXAMPLE OF A WET SCRUBBER APPLICATION FOR PARTICULATE REMOVAL ON A COAL-FIRED BOILER[6]

Plant name	Lewis and Clark Station Montana-Dakota Utilities
Boiler capacity	55 MW; about 170 MW input
Boiler type	Pulverized coal-fired
Fuel type	Coal, lignite
Sulfur content	0.45 %
Ash content	9.0 %
Wet scrubber	
Design	Venturi, flooded disc
Vendor	Research-Cottrell
L/G ratio, inlet	1.755 liters/Nm^3 (13 gal/1000 ft^3)
L/G ratio, outlet	2.295 liters/Nm^3 (17 gal/1000 ft^3)
Pressure drop	3235 Pa (13 in. H_2O)
Open or closed loop	Closed
Electric power requirement	0.5 MW
Particulate removal efficiency	98% [0.064 g/m^3 (0.028 gr/scfd)]
SO_2 removal efficiency	15% (minimum) at 0.45% sulfur content

TABLE 3.6-7. EXAMPLES OF FGD APPLICATIONS ON INDUSTRIAL BOILERS[8]

Plant name, location	No. of boilers	Total boiler capacities, MW	Total gas flow rates, Nm^3/h	Fuel, (% S)	FGD system and vendor	SO_2 removal efficiency, %
Caterpiller Tractor, Joliet, Ill.	2	18	152,500	Coal (3.2)	Double alkali (dilute), Zurn Industries	90+
FMC Soda Ash Green River, Wyo.	2	200	705,600 @160°C	Coal (1)	Sodium scrubbing, FMC	87-94
General Motors Parma, Ohio	4	32	217,600	Coal (2.5)	Double alkali (dilute), GM Environmental	90
Rickenbacker AFB Columbus, Ohio	7	20	84,750	Coal (3.6)	Limestone scrubbing, Research-Cottrell/ BAHCO	90
Kerr-McGee Chem. Corp. Trona, Calif. (under construction)	2	64	776,200 @160°C	Coke, coal or oil (0.5-5)	Sodium scrubbing, C.E.A.	98+

Note: The SO_2 removal efficiencies shown were obtained during specific test periods test periods and are not long-term averages.

3.6.3.3 Nitrogen Oxides--

Techniques for controlling NO_x from large oil-fired and pulverized-coal-fired boilers include flame temperature moderation by two-stage combustion, low-excess-air firing, and furnace modifications such as recirculation of flue gas through the combustion zone. These approaches involve reduction of peak gas temperatures and changes in the time-temperature conditions of combustion.[9]

Control of NO_x by scrubbing techniques is under active investigation, but has not yet been used on industrial boilers in the United States.[10]

3.6.4 Emission Limits

3.6.4.1 State Implementation Plan (SIP) Limits--

Most state regulations include emission limitations for industrial boilers under general regulations for fuel burning equipment. Emission limits vary with the type of fuel fired (coal, oil, or other) and with boiler size, but they do not usually specify boiler type.

Particulate emission regulations are commonly set at 43 ng/J (0.1 lb/10^6 Btu), the most stringent limitations are imposed by the District of Columbia (coal) and New Mexico (oil) as follows:

> District of Columbia (see Figure 3.6-4) --Range is about 16 to 24 ng/J (0.04 to 0.06 lb/10^6 Btu).
>
> New Mexico-- 2.7 ng/J (0.006 lb/10^6 Btu) on the basis of 7000 hours per year.

Sulfur dioxide emission regulations are frequently set at 516 ng/J (1.2 lb/10^6 Btu) for coal-fired boilers; the most stringent limitations are imposed by the State of Wyoming and Clark County, Nevada, as follows:

> Wyoming - 86 ng/J (0.2 lb/10^6 Btu).
>
> Clark County, Nevada-- 65 ng/J (0.15 lb/10^6 Btu).

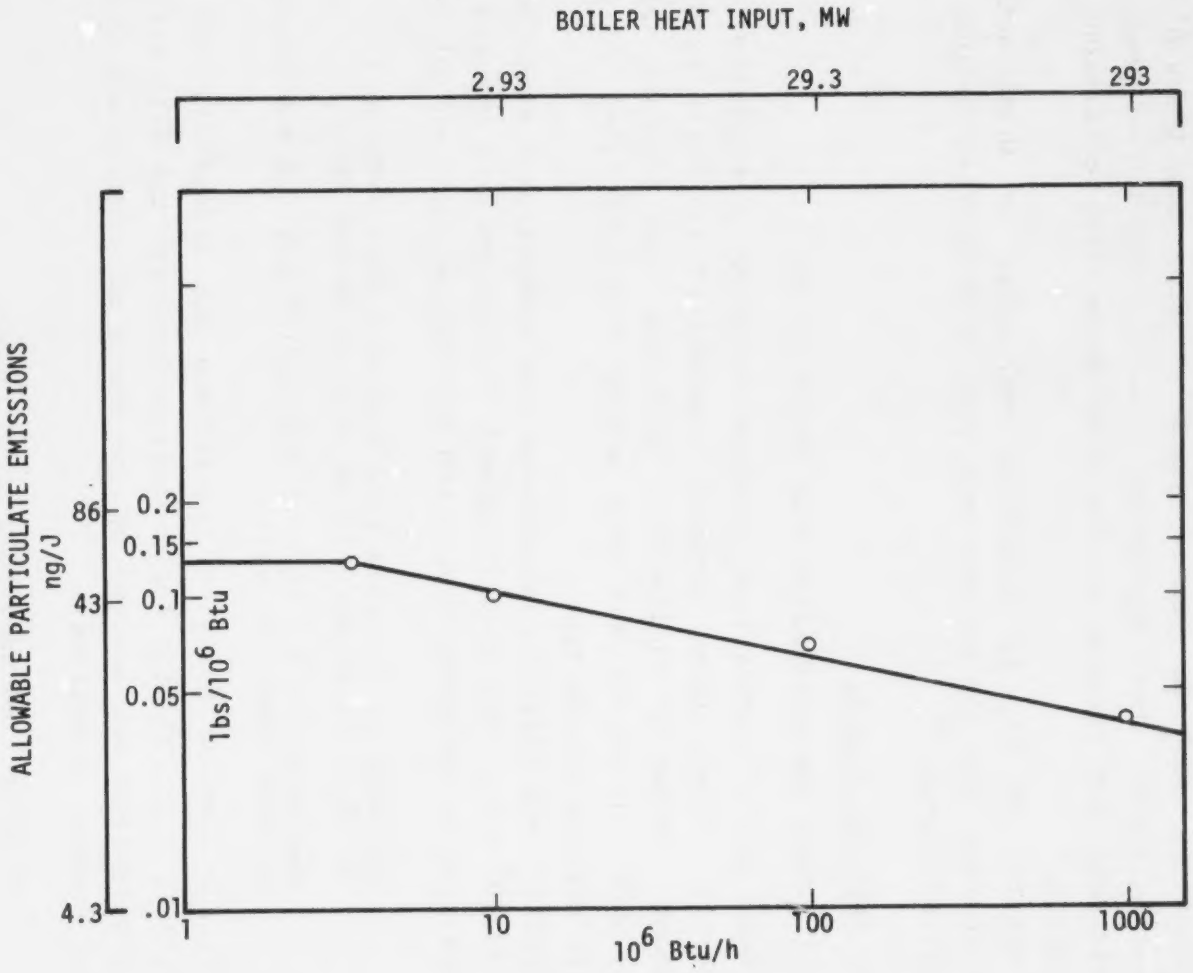


Figure 3.6-4. District of Columbia emission regulation for coal-fired boilers.

Nitrogen oxide emission regulations are generally set at 301 and 129 ng/J (0.7 and 0.3 lb/10^6 Btu) for coal and oil, respectively. The most stringent regulation is imposed by New York City: 103 ng/J (0.24 lb/10^6 Btu) for both coal and oil.

3.6.4.2 New Source Performance Standards--

Federal regulations of particulate, SO_2, and NO_x emissions apply to all types of coal- and oil-fired boilers with heat input greater than 73 MW (250 x 10^6 Btu/h). The following limitations apply to all sources that were built after August 17, 1971:

> Particulate--43 ng/J (0.1 lb/10^6 Btu); SO_2--520 ng/J (1.2 lb/10^6 Btu) for coal and 344 ng/J (0.8 lb/10^6 Btu) for oil; NO_x--301 ng/J (0.7 lb/10^6 Btu) for coal and 129 ng/J (0.3 lb/10^6 Btu) for oil.

Revisions that would reduce these emission limits are currently being studied, but no definite values have been promulgated.

3.6.4.3 Achieved-in-Practice (AIP) Limits--

Data on particulate emissions from industrial-sized boilers are often obtained under constant operating conditions with all combustion and control system parameters set at a level to minimize emissions. Under these conditions, emissions as low as 6.9 mg/m^3 (0.003 gr/dscf) were measured at the Caterpillar Tractor Co., in Decatur, Illinois, utilizing a fabric filter system.[11] This rate is approximately equal to 2.6 ng/J (0.006 lb/10^6 Btu). Emissions with fabric filter systems and high-efficiency electrostatic precipitators range more typically from 13 to 17.2 ng/J (0.03 to 0.04 lb/10^6 Btu) range. Emissions from distillate-oil-fired boilers are about 5.6 ng/J (0.013 lb/ 10^6 Btu) with no control. Well-operated residual-oil-fired boilers emit particulates in the range of 21 to 43 ng/J (0.05 to 0.1 lb/10^6 Btu) with no controls.

Sulfur dioxide emissions vary directly with fuel sulfur content. The coal-fired boiler achieving best control is the FMC plant in Green River, Wyoming, which reportedly has measured up to 94 percent SO_2 removal while burning a 1 percent sulfur content coal (see Table 3.6-7). This 3-stage tray scrubber utilizes sodium carbonate at liquid-to-gas ratios of 1.3 to 2 liters/m^3 (10 to 15 g/1000 ft^3) and a pressure drop of 2.8 to 3.2 cm (7 to 8 in.) of water.

Lowest achievable NO_x emissions are not well documented, but EPA programs to acquire NO_x emission data for large industrial boilers are scheduled for completion during 1979.

3.6.5 Determination of LAER

The recommended limitations are based on SIP's and on performance information available in early 1979. It is anticipated that several additional SIP regulations covering these sources will be promulgated and/or modified in 1979 and 1980 and that appreciable new performance data will become available in the near term. Conceivably, some SIP regulations may be more stringent than the LAER suggested herein. Furthermore, performance testing may show that more stringent limits than those suggested are feasible or it may show that the suggested limits are appropriate or that they are not achievable for some specific subcategories. In any case, the basis for determining LAER for many source categories is expected to change frequently. Since LAER is near the vanguard of control technology, a more detailed analysis is particularly necessary when addressing modified or reconstructed facilities subject to the provisions of Section 173 of the Clean Air Act. Emission limitations reasonable for new sources may in some instances be economically or technically unreasonable when applied to modified or reconstructed sources of the same type.

The following discussion pertains to coal-fired boilers in the 58 to 175 MW (200 to 600 x 10^6 Btu/h) heat input range including stokers of 88 to 117 MW (300 to 400 x 10^6 Btu/h) and to oil-fired boilers in the range of 73 to 102 MW (250 to 350 x 10^6 Btu/h) heat input. Based on particulate control efficiencies of high-efficiency fabric filter and ESP systems, an emission limit of 13 ng/J

(0.03 lb/10^6 Btu) can be achieved. This level of particulate emission will also require controls on some residual-oil-fired boilers depending on fuel composition and firing efficiency. Control efficiencies in the range of 40 to 70 percent will be required.

A sulfur dioxide emission reduction of 90 percent can be achieved on coal-fired units by use of FGD. The economic feasibility of using FGD on smaller boilers, especially those that already burn low-sulfur fuel, is questionable.

Nitrogen oxide emissions from packaged oil-fired boilers can be limited to 130 ng/J (0.3 lb/10^6 Btu). With pulverized-coal-fired boilers, a limit of 260 ng/J (0.6 lb/10^6 Btu) is achievable; this value is based on studies performed for NSPS revisions. A limit of 2.7 ng/J (0.5 lb/10^6 Btu) can be achieved by subbituminous coal-fired boilers. NO_x levels for stoker fired boilers will be determined by a current study on industrial boilers. The above limits for SO_2 and NO_x are on a 30 day average basis using a continuous monitor, while the particulate level is based upon the average of three or more runs using EPA Method 5.

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3.7 MAJOR SOURCE CATEGORY: PRIMARY ALUMINUM PLANT REDUCTION CELLS AND ANODE BAKE OVENS--SULFUR DIOXIDE EMISSIONS

3.7.1 Process Descriptions

3.7.1.1 Primary Aluminum Plant--

The base ore for primary aluminum production is bauxite, a hydrated oxide of alumina consisting of 30 to 70 percent alumina (Al_2O_3), and lesser amounts of iron, silicon, and titanium. The bauxite ore is purified to alumina by the Bayer process and then transported to the primary aluminum reduction plant.

At the reduction plant the alumina is electrolytically reduced to metallic aluminum in a bath of molten cryolite (the electrolyte) by the Hall-Heroult process. The heavier molten aluminum settles beneath the cryolite. It is periodically decanted, transferred by crucible to holding furnaces, and then cast into ingots, billets, slabs, and other bulk shapes for shipment to customers.

Figure 3.7-1 is a schematic of a primary aluminum reduction plant.

3.7.1.2 Reduction Cell--

The electrolytic reduction of alumina takes place in shallow, rectangular carbon-lined steel shells (pots) arranged in series to form a "pot line." Cryolite serves as both the electrolyte and the solvent for the alumina. Carbon blocks (anodes) are suspended in the pots (cathodes), and the two are connected electrically to accomplish the electrolytic reaction. The heat generated by electrical resistance to high-amperage, low-voltage direct current applied across the electrodes creates operating temperatures between 950° and 1000°C (1728° and 1832°F). The carbon anodes are depleted by the reaction of oxygen formed in the process ($2Al_2O_3 \rightarrow 4Al + 2O_3$) with anode carbon ($2C + O_3 \rightarrow CO + CO_2$). Because the process is continuous, both the

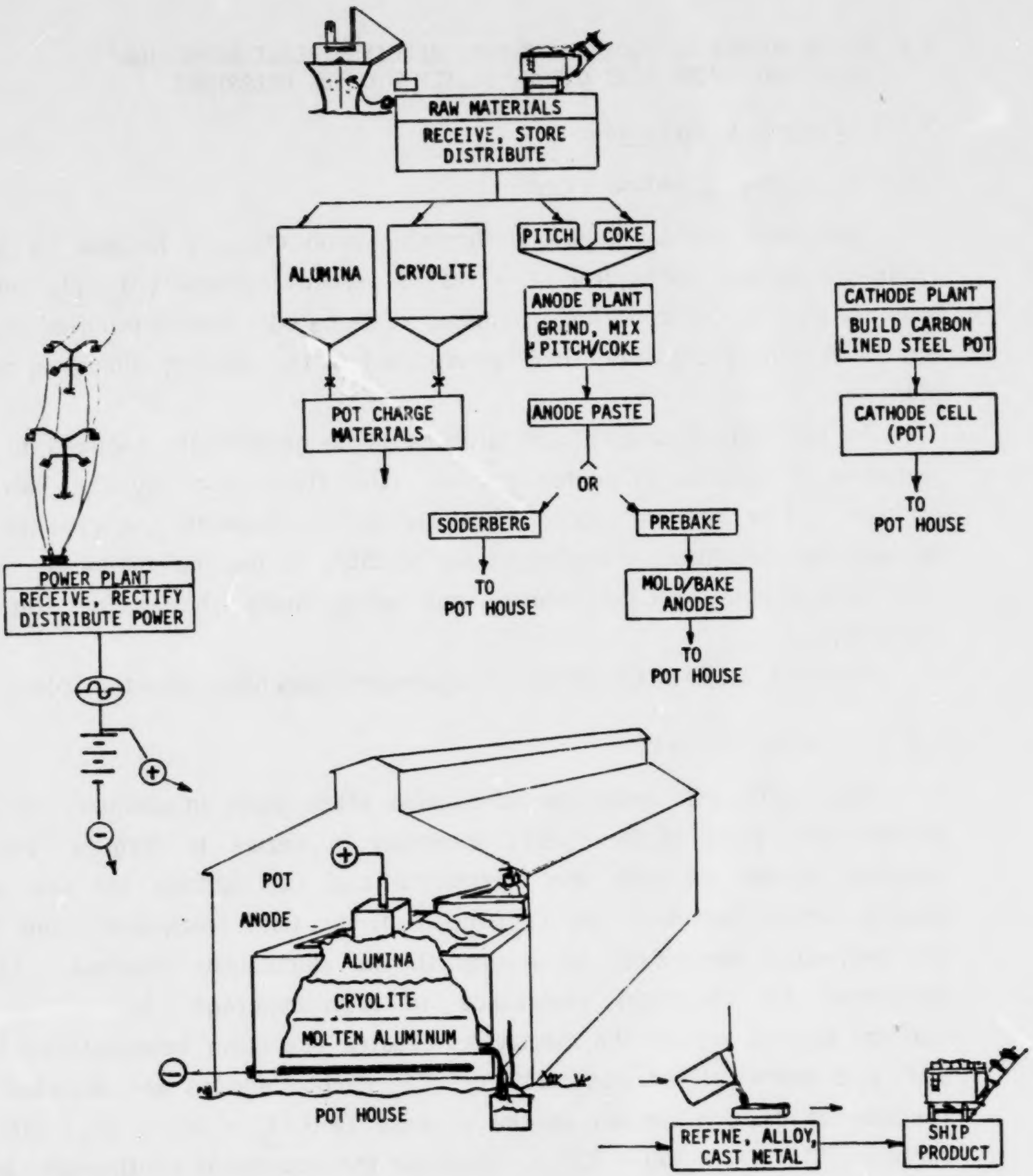
RAW MATERIALS
RECEIVE, STORE DISTRIBUTE
ALUMINA
CRYOLITE
PITCH
COKE
ANODE PLANT
GRIND, MIX & PITCH/COKE
CATHODE PLANT
BUILD CARBON LINED STEEL POT
POT CHARGE MATERIALS
ANODE PASTE
OR
SODERBERG
PREBAKE
TO POT HOUSE
MOLD/BAKE ANODES
TO POT HOUSE
CATHODE CELL (POT)
TO POT HOUSE
POWER PLANT
RECEIVE, RECTIFY DISTRIBUTE POWER
+
−
+
POT
ANODE
ALUMINA
CRYOLITE
MOLTEN ALUMINUM
−
POT HOUSE
REFINE, ALLOY, CAST METAL
SHIP PRODUCT

Figure 3.7-1. Schematic of primary aluminum reduction plant.

anodes and the cryolite-alumina bath components that are consumed or removed in the process must be replenished periodically.

Aluminum reduction cells are of two main types, prebake (PB) and Soderberg. Soderberg cells are designated according to the manner of mounting the stud in the carbon anodes: vertical stud Soderberg (VSS) or horizontal stud Soderberg (HSS). The prebake and Soderberg processes differ in the preparation of the anodes. In the Soderberg process the anode paste mixture is formed (baked) in place by the pot heat. In the prebake process, as the name implies, the anode is baked (usually in a facility separate from the pot room) before it is inserted into the pot. Although it requires more electrical power, the Soderberg cell has been favored by the industry because no separate facility is needed for manufacture of anodes. The trend in recently constructed plants, however, is to prebake anodes. One reason for this change in preference is the lower power requirements of the PB cell; another is that Soderberg cells generate volatile pitch vapors that must be captured and treated, often leading to plugging of ductwork and control devices by organic condensibles.

3.7.1.3 Prebake Anode Manufacturing--

Pitch and petroleum coke, including recycled anode butts, are mixed with a pitch binder to form a paste used in the cathodes (pot liners) and the "green" anodes for prebake cells. The approximate blend is 75 percent coke and 25 percent pitch binder. Anode making at the "green mill" (paste preparation plant) includes crushing, grinding, screening, and sizing the coke, then blending the sized coke fractions with binder in heated mixers.

For prebake anodes the paste is transferred to molds and densified by a hydraulic press or by mechanical vibration. The green anodes are then baked in furnaces to develop thermal stability, strength, and electrical conductance properties. Anodes are generally baked in a series of sunken pits (called ring-type furnaces) served by a flue system that circulates hot combustion gases from the heated pit through preceding sections to preheat the anodes. Anodes are packed into the pits, and a layer of coke is placed over and around them. The pits are fired with gas or oil through mobile manifold burners at a temperature of approximately 1200°C (2190°F). The complete cycle--charging of pits, preheating, firing, cooling, and anode removal--requires approximately 28 days.

A recent development is use of an indirect-fired tunnel kiln fitted with air locks and an inert atmosphere to preclude oxidation of the carbon anodes. This system is more complex and is subject to mechanical problems. The advantages are a shorter and more uniform baking cycle, reduced space requirements, and recycling of hydrocarbon emissions to the firebox as a fuel supplement.

The final step is to fit the baked anodes with a metal rod yoke assembly that supports the anodes in the reduction cell and provides electrical conductivity. The baked anodes are airblasted or brushed to remove surface fines; then the rod yoke assembly is mated to the anodes and cemented in place, usually with molten iron.

3.7.2 Emissions

3.7.2.1 Prebake Anode Manufacturing Emissions--

Anode paste preparation emissions--Material handling operations in anode paste preparation generate airborne particulate matter (coke dust). Spent anode butts recycled to the plant have surface deposits of pot materials that can be a source of coarse particulate fluorides in the regrinding and mixing process. Small amounts of volatile hydrocarbons are released during paste mixing. Paste preparation generates no sulfur dioxide (SO_2).

Anode bake oven emissions--Materials entering the anode bake oven (furnace or kiln) consist of the green anodes, coke or anthracite packing, and combustion fuel, either natural gas or oil. Emissions from the bake oven include the products of fuel combustion; burned and unburned hydrocarbons consisting principally of high-boiling-point organics formed by the cracking, distillation, and oxidation of the paste binder pitch; sulfur dioxide from the carbon paste; fluorides from recycled anode butts; and other particulate matter.

Sulfur dioxide emissions result from oxidation of sulfur contained in the raw materials used in anode manufacture: high-grade coke (petroleum and pitch coke) and pitch. Before calcining, the coke portion of the anode paste has already been subjected at the refinery coke operation to temperatures as high as that in the bake oven or higher; therefore, the SO_2 emissions in the bake exhaust are primarily from the sulfur in the pitch (0.5 percent sulfur) and from combustion gases. Data pertaining to SO_2 emissions from anode bake stacks are very sparse. Uncontrolled emissions in the exhaust are reported as follows: 5 to 47 ppm;[1] 0.7 to 2 kg SO_2/Mg aluminum produced* (1.4 lb to 4 lb SO_2/ton).[2] Results of source tests reported by the National Emission Data System (NEDS) indicate that emissions range from 0.09 to 1.7 kg/Mg (0.18 to 3.4 lb/ton).

3.7.2.2 Reduction Cell Emissions--

Emissions from the reduction cell include (1) particulates from the periodic addition of alumina and cryolite and from condensation of vaporized materials at the bath and anode surfaces;

(2) carbon monoxide and carbon dioxide from oxidation of carbon anodes; (3) organics (tar fog) from volatilization of the anode materials by the high-temperature bath in the cell; and (4) oxides of sulfur from the anode materials. Emissions of organics and of SO_2 are greater from Soderberg cells than from prebaked cells because the lower-boiling-point organics and some sulfur are driven off in the anode prebaking oven. In all types of reduction cells the "primary" emissions are those captured by the pot hood exhaust system and conveyed to a control device. The "secondary" (roof) emissions are those that escape the exhaust system and exit through the roof monitors.

Few measurements of SO_2 emissions from reduction cells have been reported. One report indicates up to 80 ppm in the exhaust from Soderberg plants.[1] Reference 2 reports "sulfur dioxide data ranged from 5 ppm for a prebake plant to 80 ppm for a vertical stud Soderberg plant. No sulfur dioxide data were obtained on a horizontal stud Soderberg plant." Values reported for VSS plants include a range of 200 to 300 ppm (basis of 2 percent sulfur) or 17.5 to 25 kg/Mg (35 to 50 lb/ton),[3] and a 200-ppm average.[4] Reference 2 reports emissions from prebake plants in the range of 30 kg/Mg (60 lb/ton) on the basis of 3 percent sulfur in coke, and Reference 3 gives a range of 20 to 30 ppm SO_2. NEDS data from source tests at PB plants indicate a range of 20.9 to 23.4 kg/Mg (41.7 to 46.8 lb/ton) and an average of 22.4 kg/Mg (44.8 lb/ton). NEDS gives no data on VSS or HSS facilities, and no data on HSS plants were discovered.

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* Emission values given throughout this subsection are in terms of the quantity of aluminum produced; e.g., the notation kg/Mg denotes kilograms SO_2 per megagram of aluminum produced.

3.7.3 Control Measures for SO_2

The two methods available for reducing SO_2 emissions from anode bake ovens and reduction cells at a primary aluminum plant are (1) flue gas desulfurization (FGD) systems that remove SO_2 from the exhaust stream and (2) limitations on the sulfur content of coke used in anode manufacture.

3.7.3.1 Flue Gas Desulfurization (FGD)--

Use of FGD systems has been associated primarily with the relatively strong concentrations of SO_2 in combustion gases from fossil-fuel-fired boilers at utility plants. To a lesser extent, FGD has been applied to industrial combustion and process sources. Because most applications have been for control of significant SO_2 concentrations, relatively little information is available regarding efficiency or operation of FGD on weak SO_2 streams similar to those from reduction cells and anode bake ovens. Even though FGD systems designed specifically for SO_2 control have not been demonstrated at these primary aluminum plant operations, technology transfer is possible.

Use of FGD systems has been successful on the exhausts from boilers fired with low-sulfur oil and gas, from foundry cupolas using low-sulfur coke, and from certain industrial processes.[5,6] The SO_2 concentrations in the exhaust streams from such sources approximate those from reduction cells and anode bake ovens. Collection efficiencies cited in Reference 5 range from 70 to 98 percent for boilers, 47 to 99 percent for cupolas, and 50 to 90 percent for industrial processes. As regards SO_2 control at a VSS plant, Reference 6 cites measured efficiencies of 53 to 83 percent for systems considered to be technology transfer candidates and indicates a design efficiency of 95 percent as achievable for a suggested hypothetical pot room SO_2 control system. The authors conclude that the greatest degree of control being adequately demonstrated by technology transfer candidates is approximately 80 to 85 percent. Considering the uncertainties, they believe that 70 percent SO_2 collection efficiency is achievable by transfer of technology at a VSS plant.

In the potential application of FGD to control pot room SO_2 emissions at a primary aluminum plant, it is important to recognize the differences in operation and in pot room exhaust volumes associated with VSS, HSS, and PB plants. The primary system exhaust volumes at PB and HSS plants are generally higher than those at VSS plants by 6 to 7 times and 8 to 10 times, respectively. Accordingly the larger volumes and weaker concentrations at HSS and PB plants would require proportionally larger control system capacity for anodes of a given sulfur content. Additionally, the anticipated trend to prebaked cell plants could require provision of SO_2 control on anode bake oven emissions either separately or as added primary control system capacity.

As an alternative to use of two systems--a dry fluoride/ particulate control followed by an FGD system--it would seem technically feasible to use a wet control system to capture both contaminants. Reference 6 reports that a wet scrubber/wet electrostatic precipitator system installed on a VSS plant for purposes of fluoride and particulate control collects approximately 70 percent of the SO_2 emissions from the primary system. The application of any wet system would require provision of treatment facilities to satisfy wastewater discharge requirements.

As discussed in Section 1, the determination of LAER is primarily a technology-oriented consideration, in which economics is relegated to a relatively minor role. As regards the economic impact of environmental controls in the primary aluminum industry, it has been stated that controls (associated with fluorides) more stringent than the NSPS will tend to discriminate against the small market entrant that is without existing capacity, tend to encourage a greater proportion of imports of primary ingot, and encourage higher domestic prices for primary aluminum and fabricated products.[1] Although these observations refer to the imposition of an NSPS standard for fluorides, they should also be considered when developing LAER standards for SO_2 where the control costs are substantial. Substantial costs for SO_2 control could result where the fluoride control system selected to meet the NSPS requirement would not also provide the required SO_2 control. Substantial costs could also be associated with wastewater treatment.

3.7.3.2 Limitation of Sulfur in Petroleum Coke--

Sulfur dioxide emissions from anode bake ovens and reduction cells stem from the sulfur content of the coke (usually petroleum coke) and the coal tar pitch binder. The emissions relate directly to the amount of sulfur in these raw materials, much as the SO_2 emissions from fuel combustion relate to the sulfur content of fossil fuels. Limitation of sulfur content, as is often applied to fuels, can be similarly applied to anode materials.

Good quality feedstocks for anode coke include thermal tar, cat cracker slurry, decanted oil, and coal tar pitch. Poor feedstocks include vacuum residuals and derivatives from high-sulfur crudes.[7] To some extent sulfur can be removed from coke by calcination. If the coke is to be used for anode manufacturing, however, caution must be exercised. The usual calcination temperature (1370° to 1425°C, or 2500° to 2600°F) has no deleterious effect, but high-temperature calcining (at 1590° to 1650°C, or 2900° to 3000°F) tends to cause expansion ("popcorning") of coke and to reduce its density. This effect is just the opposite of the intended purpose--densification. The expanded coke requires addition of more pitch binder at the bake step. Moreover, the baked anode becomes porous and brittle, with the deleterious effect of increased electrical resistivity and an attendant power requirement penalty.[8]

Pitch ordinarily contains about 0.5 percent sulfur; petroleum coke usually contains 2.5 to 5 percent sulfur but may have as little as 1.5 percent and as much as 7 percent.[8] The sulfur content of coke depends on the crude stock and the sulfur distribution in the crude, i.e., the tendency of sulfur to concentrate or not to concentrate in the bottoms and thus in the coke.

Marketing factors related to availability of low-sulfur coke are extremely complicated and uncertain, and the trend appears to be toward coke with higher sulfur content; however, it is reported that for the near term, coke containing 3 percent sulfur or less should be available.[7] One petroleum coke manufacturer indicates that very little low-sulfur coke (2.5 percent or less) is now available, that 4 to 5 percent coke is abundant, and that low-sulfur coke (when available) commands a price four to five times that of the high-sulfur coke.[8]

3.7.4 Emission Limits

3.7.4.1 New Source Performance Standards (NSPS) Limits--

No NSPS limitations are applicable to SO_2 emissions from anode bake oven and electrolytic reduction cell facilities at primary aluminum plants.

3.7.4.2 State Implementation Plan (SIP) Limits--

No SIP contains SO_2 emission limitations that pertain specifically to anode bake oven or electrolytic reduction cell operations. Such limitations are embodied in general regulations intended to limit SO_2 emissions from process sources. The most frequent SIP limitation on process sources limits emissions to no greater than 500 ppm SO_2 on a volume basis. The most stringent limitation is Regulation No. 2, Sec. 3122 of the Bay Area Air Pollution Control District, San Francisco, which provides that SO_2 emissions shall not exceed 300 ppm. Because the volumes of exhaust from VSS, HSS, and PB plants are variable, it is difficult to judge compliance with a 300-ppm limitation. Limited stack test data indicate, however, that SO_2 concentrations in uncontrolled exhaust from reduction cells and anode bake ovens remain below this level without the use of control equipment specifically designed for SO_2 removal.

3.7.4.3 Achieved-in-Practice (AIP) Limits--

As mentioned earlier, no FGD systems specifically designed for SO_2 control on HSS, VSS, and PB pot lines have been installed at primary aluminum plants in the United States. At a VSS plant the wet systems used to control particulate and fluoride reportedly also capture 70 percent of the SO_2

in the primary exhaust and 45 percent of the SO_2 in the secondary (roof) system. (Emissions are approximately 6.3 kg/Mg or 12.6 lb/ton, with a basis of 2 percent sulfur coke.[6])

One aluminum producer reportedly will install FGD systems at two VSS plants.[3,6] The proposed system will consist of a wet scrubber following a dry fluoride/particulate control device serving the pot exhaust and an existing wet scrubber for secondary (roof) emissions. With changes in cell technology, 95 percent capture and transport of cell emissions to the primary system (5 percent to secondary system), and attentive cell operational procedures, it is expected that overall SO_2 control efficiency will be about 84 percent. Resultant SO_2 emissions, based on use of 2.8 percent sulfur coke (and an alumina sulfur content of 0.045 percent), are projected to be 4.1 kg/Mg (8.1 lb/ton). The installation is in response to a PSD-BACT determination that gave approval subject to an emission limitation of 9.5 kg/Mg (19 lb SO_2/ton).[6]

No achieved-in-practice information was discovered relative to ancillary control of SO_2 by wet fluoride/particulate control systems on PB, HSS, or anode bake plants. Several PSD-BACT review determinations on PB plants have been approved with an SO_2 limitation based on 3 percent sulfur in the coke. In the absence of other specific information, the achieved-in-practice limitations are those values given in Section 3.7.2, Emissions.

In summary, for both anode bake ovens and reduction cells, the applied controls based on wet methods were designed and installed for the primary purpose of controlling fluoride and particulates; reduction of SO_2 emissions is generally secondary and incidental; emission measurements are oriented toward fluoride/particulates; and SO_2 emissions are largely unreported. Because SO_2 emissions are directly related to sulfur content of the coke, the best achieved-in-practice levels are usually use of low-sulfur coke rather than application of control technology.

3.7.5 Determination of LAER

The recommended limitations are based on SIP's and on performance information available in early 1979. It is anticipated that several additional

SIP regulations covering these sources will be promulgated and/or modified in 1979 and 1980 and that appreciable new performance data will become available in the near term. Conceivably, some SIP regulations may be more stringent than the LAER suggested herein. Furthermore, performance testing may show that more stringent limits than those suggested are feasible or it may show that the suggested limits are appropriate or that they are not achievable for some specific subcategories. In any case, the basis for determining LAER for many source categories is expected to change frequently. Since LAER is near the vanguard of control technology, a more detailed analysis particularly is necessary when addressing modified or reconstructed facilities subject to the provisions of Section 173 of the Clean Air Act. Emission limitations reasonable for new sources may in some instances be economically or technically unreasonable when applied to modified or reconstructed sources of the same type.

No NSPS limitations are applicable to sulfur dioxide emissions from either anode bake ovens or reduction cell pot lines at primary aluminum plants. Limited stack test data indicate that uncontrolled emissions are within the most stringent limitation embodied in a State Implementation Plan. For both anode bake oven and reduction cell emissions, the achieved-in-practice levels are highly variable and depend primarily on the coke sulfur content. Emission data are insufficient, particularly for anode bake ovens or HSS or PB cell plants, to allow definition with any degree of confidence of a best achieved -in-practice level.

The most practical method of limiting SO_2 emissions from primary aluminum plants is to utilize low-sulfur materials in the anodes. The sulfur content of coke is directly related to the quality of the crude from which it is produced. Supplies of 3 percent sulfur coke derived largely from domestic crude are expected to be available for the next 5 to 10 years. Since future supplies of coke will depend primarily on foreign crudes, the future availability of low-sulfur coke is uncertain. Given the domestic dependence on and the competing demands for various petroleum products, it is unadvisable to suggest a single value that would purport to represent LAER when the determining emission parameter--coke sulfur content--is uncertain.

It is appropriate to suggest factors to be considered in deriving LAER once a specific case is in hand and the unknowns are resolved. The following are therefore presented as general guidance to be considered in determining LAER for SO_2 emissions from primary aluminum reduction plants.

3.7.5.1 Sulfur-in-Coke Limitation--

For all plant types consider a limitation on sulfur content in coke that reflects the lowest-sulfur coke available. The limitation should allow no greater than 3 percent sulfur in coke and lesser-sulfur coke should be required unless it can be adequately demonstrated that it is not available. Coke blending should be considered where supplies of low-sulfur coke are available but limited in quantity.

3.7.5.2 Application of FGD--

Consider the application of FGD on a case-by-case basis. In examining the merits of applying FGD technology to aluminum reduction plant emissions the following general observations are worthy of consideration:

At this time FGD systems have not been applied to primary aluminum plant facilities for the sole and specific purpose of SO_2 control. Wet systems installed for particulate and fluoride control at a VSS plant have, however, reportedly effected a 70 percent SO_2 removal in the secondary system. In addition, proposed FGD systems at two VSS plants are to be installed as a result of BACT determinations and are expected to provide an overall SO_2 control efficiency of approximately 84 percent. The use of FGD appears to be technically feasible at aluminum reduction plants, although costs are expected to be high compared with those associated with FGD use at power plants.

Because of the lower exhaust volumes and higher SO_2 concentrations resulting from coke of a given sulfur content, FGD is more readily applicable to VSS than to HSS or prebake facilities. The larger exhaust volumes and attendant dilute SO_2 concentrations at HSS and PB plants would necessitate much larger FGD system capacity than for a VSS plant. New plants are expected to be of the PB type.

Wet systems used to control particulates and fluorides may be utilized to achieve SO_2 control as well. Where wet systems cannot be adapted to achieve adequate SO_2 control, two systems could be used to satisfy LAER and NSPS limitations. Depending on the sulfur content of the coke used and the resultant SO_2 emission rate, consideration could be given to specifying a LAER limitation that could be met by excellent capture and FGD treatment of primary emissions only. In such case neither the secondary emissions from reduction cells nor the bake plant emissions would require FGD treatment.

Wet scrubber effluent must be handled in a manner that conforms with wastewater treatment standards and water quality requirements.

Costs associated with installation of FGD systems and attendant wastewater treatment facilities would exercise economic constraints on the viability of constructing a new (modified) primary aluminum reduction facility.

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3. Personal communication with Fred Fenske, Washington State Department of Ecology, May 10-11, 1978.

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7. Internal Memo - Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina. Reid Iverson to Gordon Rapier re: Determination of BACT for SO_2 Emissions from Primary Aluminum Plant. December 19, 1977.

8. Personal communication with Richard Albrecht, Sohio, Cleveland, Ohio, April 12, 1978.

3.8 MAJOR SOURCE CATEGORY: BULK GASOLINE TERMINALS TRUCK LOADING OPERATIONS--VOLATILE ORGANIC COMPOUNDS (VOC)

3.8.1 Process Description

Gasoline and other liquid petroleum products are distributed from the refinery to the consumer by an extensive network of pipelines, tank trucks, railroad tank cars, and marine tankers or barges. The bulk gasoline terminal is an integral part of this network, serving as the primary storage and distribution facility for a regional marketing area. Within this area it provides products to smaller but similar distribution facilities, called bulk plants, that serve smaller, localized areas. In this report, a bulk terminal is defined as a distribution facility with an average daily gasoline throughput of greater than 76,000 liters (≅20,000 gallons) and a bulk plant as one with an average daily gasoline throughput of 76,000 liters or less. The bulk terminal receives gasoline by pipeline, ship, rail, or barge; stores it in tanks; then redistributes it by tank-truck to bulk plants, commercial accounts, or retail outlets.

Equipment and structures at the typical bulk terminal include storage tanks, loading (unloading) equipment, liquid lines, tank trucks, parking and access roadways, and business offices. The gasoline is usually stored above grade in floating-roof tanks that have large storage capacities [generally greater than 250,000 liters (65,000 gallons) at new installations]. The loading facility consists of equipment to meter and deliver gasoline into tank trucks from the storage tanks. It is located at a central island (loading rack) accessible to tank trucks. The loading rack may be at grade level to accommodate bottom filling of tank-trucks or above grade for loading through top hatches. Liquid lines provide the link between storage tanks, the loading rack, and the tank truck. This guidance pertains to emissions of voltaile organic compounds (VOC) during the truck loading operations at bulk terminals.

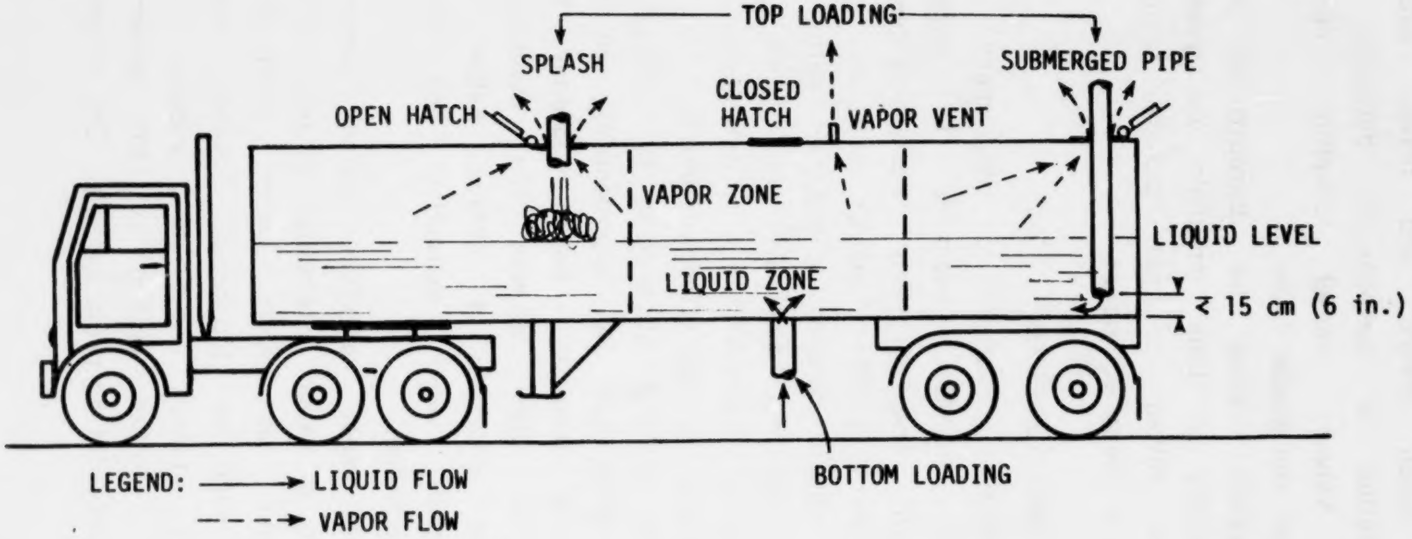
3.8.2 Emissions

Volatile organic compound emissions at bulk terminals can occur from storage tanks when the contents are at rest, during transfer (loading) of gasoline from storage tank into tank truck, from the tank truck, and at points along the gasoline liquid or vapor plumbing lines. Evaporative emissions from these sources are categorized as standing storage or "breathing" loss, liquid transfer or "working" loss, and miscellaneous or "fugitive" loss. VOC emissions from storage tanks are discussed in Section 3.10, "Gasoline and Crude Oil Storage."

Working loss from tank trucks results from the active movement of liquids, most commonly when vapors are displaced from a vessel as liquid is added. Working loss includes both filling and emptying or drainage losses, i.e., the vapors displaced during filling and those generated after draining by the interaction of residual liquid and the air introduced into the vessel. The quantity and composition of emissions are related to the physical and chemical characteristics of the old (residual) and the new (loading) cargo; the rate and amount of unloading and loading; leakage from the vessels; the liquid lines and their connections and fittings; temperature differentials between vessels and liquids; and, most importantly, the loading method, whether splash or submerged fill.

Figure 3.8-1 depicts the several tank truck loading methods: overhead, either by splash- or submerged-fill pipe, and bottom fill. Top-splash fill generates relatively greater amounts of vapors because of turbulence and the opportunity for contact of vapor, air, and liquid during the liquid free-fall. Both submerged fill, wherein the fill tube is always near or below the liquid level, and bottom fill, wherein the inflow is always below the liquid surface, minimize vapor generation, turbulence, and VOC emission.

Fugitive losses, largely preventable, result from improper operation and maintenance, faulty equipment, and human error.


TOP LOADING
SPLASH
OPEN HATCH
CLOSED HATCH
VAPOR VENT
SUBMERGED PIPE
VAPOR ZONE
LIQUID LEVEL
LIQUID ZONE
≈ 15 cm (6 in.)
BOTTOM LOADING
LEGEND: ——→ LIQUID FLOW
- - -→ VAPOR FLOW

3.8-1. Loading methods.

Such losses include leaks from liquid and vapor lines, connections, hatch covers, and fittings caused by improper mating or deterioration of components; defective or maladjusted sensors and relief valves; vessel overfills; open hatches; backflow and drainage; and similar losses.

Typical values for uncontrolled emissions from truck loading of gasoline at bulk terminals are presented in Table 3.8-1. The emission values do not include fugitive emissions due to inept loading or faulty equipment.

3.8.3 Control Measures

Effective control of tank-truck loading operations at bulk terminals includes measures to suppress vapor generation; a vaportight and properly sized system for capturing, collecting, and conveying the vapors; and an efficient means of vapor disposal. Such measures, together with design features that enhance vapor capture, disposal, and spill prevention; good operational procedures; preventive maintenance practices; and attentive housekeeping provide effective control.

The use of submerged fill rather than splash loading reduces vapor generation by approximately 58 percent.[1] Of the two submerged-fill methods, bottom loading is preferred over a submerged-fill pipe because the installation is much simpler, the inflowing gasoline is always below the liquid level, and the independent vapor extraction and gasoline filler lines facilitate vapor collection.

The vapor collection system captures the vapors and conveys them to a vapor processing system. The system must be maintained vaportight throughout, with particular attention to leak-prone points such as top-hatch closures, vapor holders, knockout (condensate) tanks, backflow valves, and pressure-vacuum relief valves. Proper setting of fill meters and valves is important, particularly during rapid loading. The system should incorporate

TABLE 3.8-1. HYDROCARBON EMISSION FACTORS FOR LOADING GASOLINE INTO TANK CARS AND TRUCKS[a]

Emission source[b]	Emission factor[c]
Submerged loading--normal service	
$lb/10^3$ gal transferred	5.0
$kg/10^3$ liters transferred	0.6
Splash loading--normal service	
$lb/10^3$ gal transferred	12.0
$kg/10^3$ liters transferred	1.4
Submerged loading--balance service	
$lb/10^3$ gal transferred	8.0
$kg/10^3$ liters transferred	1.0
Splash loading--balance service	
$lb/10^3$ gal transferred	8.0
$kg/10^3$ liters transferred	1.0

[a] Reference 1, p. 4.4-8.

[b] The gasoline used in this example has a Reid vapor pressure of 10 psia.

[c] Emission factors are calculated for a dispensed fuel temperature of 60°F.

design features that prevent vapor backflow (drainage) when connections are removed, maintain a vaportight connection as the tank vehicle settles with increasing load, and eliminate the need for open "topping," i.e., visual observation as liquid level is adjusted to tank capacity. Gasoline loading lines should incorporate similar features to prevent liquid leaks and drainage spills. Tests at bulk terminals have shown that 30 to 70 percent of the vapors can escape capture at the truck.[2]

A recent EPA publication on reasonably available control technology (RACT) states the importance of maintaining vapor- and liquid-tight systems and the techniques for detecting, controlling, and minimizing leaks from tank trucks and vapor collection systems.[3] This publication defines leak-tight conditions for RACT; describes compliance test methods and procedures for ascertaining the degree of leak-tightness and for detecting leaks; and suggests useful record keeping, inspection, and reporting methods for ensuring that leak-tight conditions are maintained. The equipment performance criteria and the regulation recommended in this publication are briefly discussed below.

Both the compliance test procedure and the recommended regulation in this publication define a "leak-tight condition" as one that is equivalent to 99 percent capture efficiency during vapor transfer from a truck tank. The publication points out that this capture efficiency will decrease because some sources (e.g., pressure and vacuum valves and hatch seals) may leak shortly after maintenance. The suggested control approach of the publication is to encourage more frequent and effective maintenance procedures and adherence to the test and monitoring procedures described below. The recommended regulation states that gasoline tank trucks and their vapor collection systems (which are tested annually) should not sustain a pressure change of more than 750 pascals (3 in. of water) in 5 minutes when pressurized to 4500 pascals (18 in. of water) or evacuated to 1500 pascals (6 in. of water). For tank trucks and vapor collection systems, a combustible gas detector is used as a monitoring procedure to ascertain leak-tightness. During loading operations, the recommended regulation requires that no reading be greater than or equal to 100 percent of the lower explosive limit (LEL, measured as propane) at 2.5 cm (1 in.) around the perimeter of a potential leak source in the system. (The vapor collection system includes all piping, seals, hose connections, pressure-vacuum vents, and other possible leak sources between the truck and the vapor processing unit and/or the storage tanks and vapor holder.)

The recommended regulation further requires that the vapor collection and vapor processing system be designed and operated to prevent gauge pressure in the tank truck from exceeding 4500 pascals (18 in. of water) and prevent vacuum from exceeding 1500 pascals (6 in. of water). No visible liquid leaks that can be avoided are allowed from either the tank truck or the vapor collection system.

Two general types of vapor processing systems are applicable to bulk terminal truck loading: systems that thermally destroy the vapors, and systems that recover the vapors as useful product. It is emphasized that the values for mass emission rates at the outlet of the vapor processing units discussed below will vary with the leak-tight condition of the tank trucks and vapor piping.

Thermal oxidizers (destructors, afterburners, or incinerators) are commonly used at some industrial processes for the control of combustible aerosols, vapors, gases, and odors. At gasoline terminals the thermal oxidizer (TO) converts gasoline vapors to essentially carbon dioxide and water rather than recovering them as liquid gasoline. The most effective type of TO unit consists of a vapor holder, propane tank, burner (flare), and associated piping. Gasoline vapors are directed to the vapor holder, where propane is added when necessary to maintain the VOC/air ratio above the flammability limit. Vapors are drawn from the vapor holder, pass through the burner, mix with metered air, and are combusted. Later models of TO systems do not require a vapor holder; the vapors from tank trucks are vented directly to the TO unit. Requisite safety features include flashback and safety interlock flame guards and automatic malfunction shutdown; heat recovery is optional. The TO units have been used for the destruction of VOC vapors from bulk terminal operations. The EPA test results on four TO units--two with vapor holders and two without--indicated average mass emission rates at the outlet of 8.7, 1.3, 28.5 and 31 mg/liter loaded.[4-8]

Vapor recovery systems used at bulk terminals include those employing compression-refrigeration-absorption (CRA), compression-refrigeration-condensation (CRC), straight refrigeration (RF), and carbon adsorption (CA). The technology of these systems is well understood; the reliability and control efficiencies are good and are being improved.

The CRA unit is based on the absorption of gasoline vapors under pressure with cool gasoline from storage. The system generally includes a saturator, vaposphere, chilled gasoline absorber, compressor, pumps, and instrumentation. Incoming vapors are passed through the saturator and sprayed with gasoline as a safety measure to ensure that the vapor concentration is above the explosive level. The vapors are then compressed, cooled, and passed to the absorber, where they are brought into contact with chilled gasoline. The bottoms from the absorber containing gasoline and the absorbed vapors are returned to storage, and the remaining air is vented to the atmosphere. The EPA test results on four CRA units indicated average mass emission rates at the outlet of 59, 43, 40, and 31 mg/liter of gasoline loaded.[9-13]

The straight refrigeration (RF) system condenses vapors by refrigeration at atmospheric (ambient) pressure. Since vapors are treated on demand, no vapor holder is required. The vapors are fed directly to the condenser, cooled to minus 73°C (minus 100°F), and condensed. Condensate is withdrawn from the condenser bottom and air is vented from the top. The stored brine is cooled by a two-stage refrigeration unit. Cooling for condenser coils is supplied by methyl chloride. The EPA test results on three RF units indicated average mass emission rates at the outlet of 63, 37, and 34 mg/liter of gasoline loaded.[14-17]

Carbon adsorption (CA) systems are based on the affinity of activated carbon for hydrocarbon vapors. Equipment consists of twin activated carbon beds, a vacuum regeneration unit, a condenser-separator, and pumps. Inlet vapors are passed through a carbon bed, the gasoline vapor is adsorbed on the activated carbon, and air is vented to the atmosphere. The adsorbed vapors are then vacuum-stripped and passed to the condenser-separator. The recovered gasoline is pumped to storage. The air and any remaining hydrocarbons are recycled from the condenser-separator through the carbon bed to the atmosphere. During operation one carbon bed is in the adsorption cycle and one is in the desorbtion or regeneration cycle. The EPA test results on two CA units indicated average mass emission rates at the outlet (during normal periods of operation*) of 3, 10, and 2 mg/liter of gasoline loaded.[18-20]

3.8.4 Emission Limits

3.8.4.1 New Source Performance Standards (NSPS) Limits--

No NSPS are applicable to VOC emissions from the loading of tank trucks at bulk gasoline terminals.

3.8.4.2 State Implementation Plan (SIP) Limits--

Air pollution control regulations of some state and local agencies contain provisions specifically applicable to gasoline transfer operations. Table 3.8-2 lists major provisions of the more restrictive of such regulations as they apply to gasoline loading at bulk terminals.

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* The emission rates during abnormal unit operations were not calculated for the average mass emission rate at the outlet; e.g., emission rates during incorrect timer settings (Reference 18), and while the unit was purposely overloaded (Reference 19).

TABLE 3.8-2. STATE IMPLEMENTATION PLAN (SIP) REQUIREMENTS APPLICABLE TO GASOLINE LOADING OPERATIONS OF BULK TERMINALS[a]

SIP agency	Regulatory requirement
California[b]	
San Francisco Bay area	Organic emissions with vapor pressure greater than 10.3 kPa (1.5 psia) shall be reduced by at least 90% of the amount that would be emitted without controls. Submerged fill pipe.
South Coast	Vapor collection and disposal system or equal required; vapor disposal system (if absorber or condensation system) must recover 90% by weight of vapors.
Colorado	Vapor collection and disposal system or equal required; drainage prevention; vaportight lines at all times; all vapors to vapor recovery or disposal unit; final emissions not to exceed 0.155 kg/liter (1.24 $lb/10^3$ gal) loaded.
New Mexico	
Alburquerque	Similar to Colorado regulations.
Missouri	
St. Louis	Vapor recovery system or equal required; adsorber, condensation, or equal systems must limit discharge of hydrocarbons to 0.5 g/gal (0.13 kg/kl or 1.1 $lb/10^3$ gal) loaded.

[a] Gasoline loading facilities having an average daily throughput greater than 76,000 liters (20,000 gal).

[b] The 90 percent requirement in the California area regulations would be approximately equivalent to an emission limit of 0.14 kg/kl (1.2 $lb/10^3$ gal), i.e., (1-0.9) x uncontrolled VOC emission factor of 1.4 kg/kl (12 $lb/10^3$ gal).

Table 3.8-2 illustrates the similarity of formats and emission limitations in SIP regulations. The most stringent limitation is that of Missouri for the St. Louis area, which requires that vapor recovery system or equal be provided, displaced vapors be vented to vapor recovery system, drainage spill be prevented, and the vapor disposal system meet an emission limit of 130 mg/liter (1.1 lb/10^3 gal). Some state SIP regulations are presently being revised to reflect the stricter requirements (an emission limit of 80 mg/liter loaded) achievable with RACT.

3.8.4.3 Achieved-in-Practice (AIP) Limits--

Available test data indicate the control efficiency achieved in practice with some types of TO and CA units approaches 99.9 percent. Slightly lower control efficiencies have been reported for other vapor recovery units. It is emphasized that these values pertain to the emission reduction across the control device only and therefore assume 100 percent collection and transport of vapors to the disposal unit--a condition that has not been observed in practice.

3.8.5 Determination of LAER

The recommended limitations are based on SIP's and on performance information available in early 1979. It is anticipated that several additional SIP regulations covering these sources will be promulgated and/or modified in 1979 and 1980 and that appreciable new performance data will become available in the near term. Conceivably, some SIP regulations may be more stringent than the LAER suggested herein. Furthermore, performance testing may show that more stringent limits than those suggested are feasible or it may show that the suggested limits are appropriate or that they are not achievable for some specific subcategories. In any case, the basis for determining LAER for many source categories is expected to change frequently. Since LAER is near the vanguard of control technology, a more detailed analysis is particularly necessary when addressing modified or reconstructed facilities subject to the provisions of Section 173 of the Clean Air Act. Emission limitations reasonable for new sources may in some instances be economically or technically unreasonable when applied to modified or reconstructed sources of the same type.

No NSPS limitations are applicable to VOC emissions from tank-truck loading at bulk gasoline terminals. The most stringent SIP imposes an emission limit of 130 mg/liter (1.1 lb/10^3 gal) loaded. Emission values less than this SIP limitation have been achieved in practice.

LAER for tank-truck loading operations at bulk terminals is determined to be an emission limit of 30 mg/liter (0.25 lb/10^3 gal) of gasoline loaded and requires an overall system efficiency of 97 percent. On the basis of EPA emission test data, this value appears achievable with thermal oxidizer, carbon adsorption, or other vapor recovery units operated at optimal efficiency in conjunction with a highly effective capture-collection system that provides virtually leakproof transport of vapors to the control unit.

It should be emphasized that effective vapor collection and leak-tight delivery to the processing unit are required to maintain the integrity of the vapor control system and to minimize VOC emissions. The RACT performance criteria, compliance test methods, and other related requirements are recommended for attaining and maintaining a leak-tight system.

The following measures are designed to reduce or preclude VOC emissions and to support LAER controls.

1. System design features that provide vaportight connections at all times, incorporate closed hatch "topping," accomodate vehicle settling, prevent venting of the relief valve during loading at maximum rate, prevent all backflow or drainage when connections are made or disengaged, and provide maximum legal release pressure for all relief valves.

2. Supervised standard operating practices that curtail VOC loss due to poor housekeeping and/or operating procedures. Examples of poor operating practices include excessive fill rates that increase vapor generation and pressures, improper setting of fill meters (causing overfills), careless or improper connections, improperly set pressure/vacuum relief valves, and open hatches.

3. Supervised programs of preventive maintenance and scheduled inspections with the objective of maintaining liquid- and vapor-tight systems, preventing leaks in liquid/vapor plumbing and fittings, and repairing or replacing defective or malfunctioning hardware.

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3.9 MAJOR SOURCE CATEGORY: FLAT WOOD PANELING--VOLATILE ORGANIC COMPOUNDS (VOC) EMISSIONS

Flat wood products include a variety of materials such as plywood, particleboard, hardboard, panelboard, fiberboard, insulation board, and molding. In 1976 approximately 640 flat wood plants were in operation; 247 of these were hardwood plywood and 240 were softwood plywood plants.[1]

Plants that apply coatings to their wood products generate emissions of volatile organic compounds (VOC), which is the subject of this section. On the basis of membership in national associations of flat wood producers, it is estimated that 40 percent of hardwood plywood plants, 10 percent of the softwood plywood plants, and under 15 percent of the particleboard plants apply coatings.[1] For this reason, the major emphasis in this guidance is directed toward the hardwood plywood industry. It is intended to apply to printed interior wall panels made from hardwood plywood and thin particleboard, natural finish hardwood plywood panels, and Class II finishes for hardboard paneling. Segments of the flat wood products industry not addressed are exterior siding, tileboard, and particleboard used as a furniture component.

3.9.1 Process Description

Figure 3.9-1 is a general flow diagram of flat wood coating processes utilizing conventional coatings with organic solvents. As the diagram indicates, the first operation has an optional step, the sanding of particleboard before it enters the brushing unit. All other flat wood products go directly to the brushing operation. After the brushing operation, the stock is directed to a reverse-roll coater for filler application. Normally, filler is not applied to hardboard before the application of a base coat.[2] If the panel is not to be filled, it bypasses the filler and drying oven and proceeds to a direct-roll coater for application of a sealer or first base coat. Drying ovens can be gas-fired or electrically heated. If ultraviolet-curable coatings (commonly called UV coatings) are applied, a UV oven is used for curing.

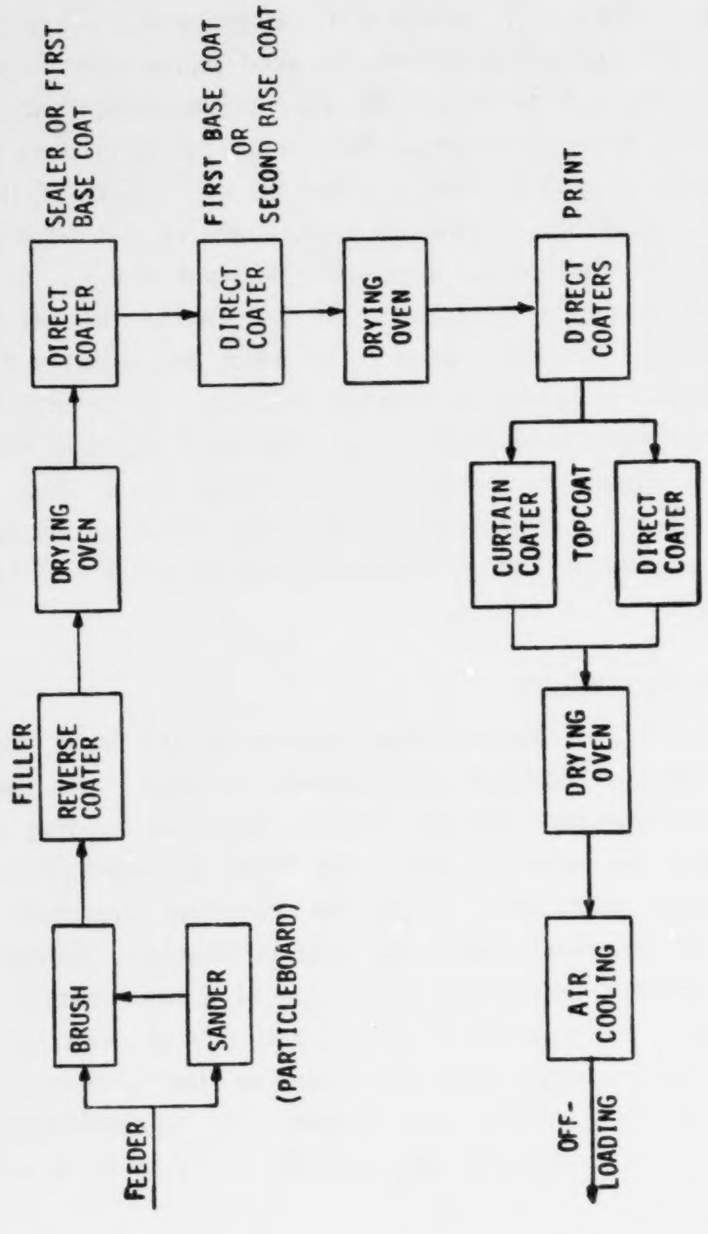

FEEDER
BRUSH
SANDER
(PARTICLEBOARD)
FILLER
REVERSE COATER
DRYING OVEN
DIRECT COATER
SEALER OR FIRST BASE COAT
DIRECT COATER
FIRST BASE COAT OR SECOND BASE COAT
DRYING OVEN
DIRECT COATERS
PRINT
CURTAIN COATER
TOPCOAT
DIRECT COATER
DRYING OVEN
AIR COOLING
OFF-LOADING

Figure 3.9-1. General process flow.

The most common flat wood products coated by the industry are plywood, particleboard, and hardboard. A few plants coat pine and cedar siding. Coatings that can be factory-applied include filler, sealer, base coat, ink, and topcoat. Fillers are used to fill voids and cracks in the wood to provide a smooth surface. Sealers seal off pores and substances in the wood that may affect subsequent finishes. Base coats are used as the primary coating/coloring of the panels, and inks are used only for decorative or simulated grain panels. Topcoats provide both a protective coating and a finished appearance. Not all factory-prefinished wood products undergo the complete series of coatings. For instance, a sealer is not required after the application of certain fillers; also, some builders are losing interest in topcoat-finished materials because they damage easily during installation.

Following application of the sealer or first base coat, a second direct-roll coater is used to apply an initial or a second base coat to the panel. The filled, sealed, base-coated board can be shipped as is after drying, or it can be given wood grain or topcoats. The grainprinter is a direct-roll coater. Usually, three or four such printers are used in series to provide different colors of grain. After it is printed, the panel goes through a direct-roll coater or a curtain coater (often used by plywood coating plants) to receive a protective coat. The panel then goes through a drying oven for curing before shipment.

Similar processes are used by plants with waterborne coating systems. The main differences are longer ovens, lower operating rates, or higher oven temperatures (for proper curing).

Among the several methods of applying coatings to flat wood, the preferred ones are roll coating and curtain coating. In roll coating (Figure 3.9-2) the coating material is applied to the wood by cylindrical rollers. If the cylinder rotates in the same direction as panel movement, the applicator is called a direct-roll coater, generally used to apply base coat, print, and topcoat. If the cylinder rotates in the opposite direction of panel movement (reverse-roll coater), the coating is forced into voids and cracks in the panels, fills these depressions, and provides a smooth surface.

In curtain coating (Figure 3.9-3), used mostly for topcoating, the coating material forms a curtain through which the panel passes. Coating material is metered into a pressure head and is forced through a calibrated slit between two knives to form a continuous, uniform curtain. The rate of panel movement determines the coating thickness. All excess coating is caught in a trough and recirculated.

3.9.2 Emissions

Volatile organic compounds are emitted by the evaporation of volatile organic solvents used in conventional coatings applied to flat wood products. Small quantities of dust and smoke also may be emitted to the atmosphere.

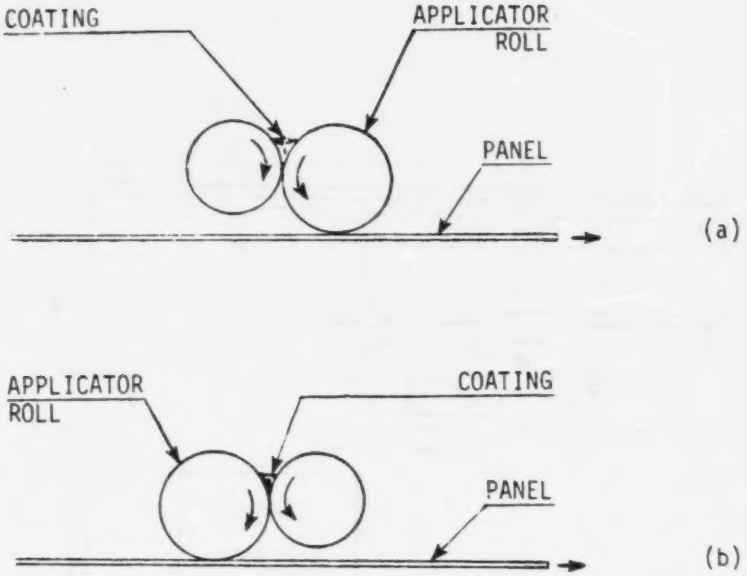
3.9.2.1 Nationwide Emissions--

No more than one-quarter of the U.S. plants that turn out flat wood products apply coatings. Most of these are primarily hardwood plywood plants, and in some cases they coat only a small percentage of production.[1]

In 1975 the total VOC emissions from all flat wood plants was estimated to be 67,000 Mg (74,000 tons). This estimate is based on annual coating usage of 132 Mm^3 (35 x 10^6 gal),[3] an average emission factor of 0.5 kg VOC/liter (4.2 lb/gal)[4] of coating, and no emission control. In the same year, VOC emissions from stationary and automotive sources were estimated to be 17.3 Tg (19 x 10^6 tons) and 10.8 Tg (12 x 10^6 tons).[5] Therefore, VOC emissions from flat wood products manufacturing account for less than 0.4 percent of emissions from stationary sources, or about 0.2 percent of all VOC emissions.

3.9.2.2 Sources and Quantity of VOC Emissions[6]--

Emissions of volatile organic solvents at flat wood coating plants occur primarily at the coating lines. Oven exhausts are discrete point sources, and coaters and rollers are termed fugitive emission sources. Solvents used in organic-based coatings are normally multicomponent mixtures that may include methyl ethyl ketone, methyl isobutyl ketone, toluene, xylene, butyl acetates, propanol, ethanol, butanol, VM and P naphtha, methanol, amyl acetate,


COATING
APPLICATOR ROLL
PANEL
(a)
APPLICATOR ROLL
COATING
PANEL
(b)

(ARROWS SHOW DIRECTION OF ROLLER AND PANEL MOVEMENTS)

Figure 3.9-2. **Simplified schematic of roll coaters.** (a) direct-roll coater, (b) reverse-roll coater.

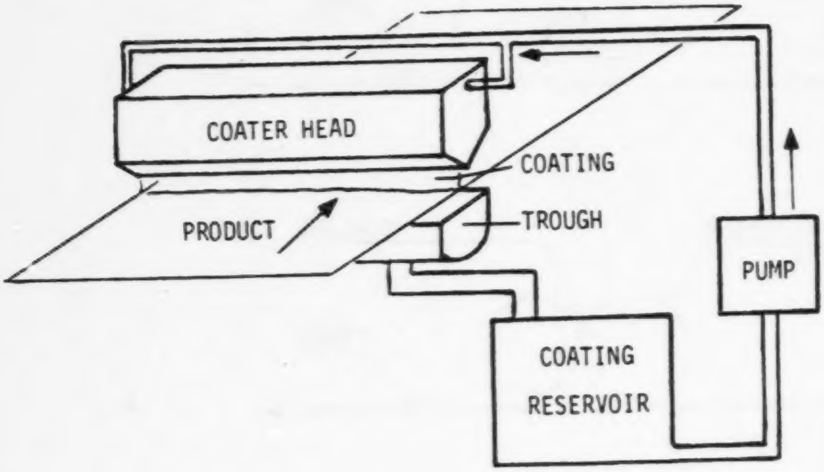

COATER HEAD
COATING
TROUGH
PRODUCT
PUMP
COATING RESERVOIR

Figure 3.9-3. Pressure head curtain coater.

mineral spirits, SoCal I and II, glycols, and glycol ethers. Organic solvents most often used in waterborne coatings are glycol, glycol ethers (such as butyl cellosolve), propanol, and butanol. Contents of volatile organics in the different types of conventional coatings supplied to the flat wood coating industry are shown in Table 3.9-1 with estimated emission factors. The composition of the solvent determines the type of VOC emitted. Waterborne coatings are discussed under control measures.

3.9.2.3 Factors Influencing VOC Emissions--

Table 3.9-2 lists the common organic solvents used in conventional coatings and their vapor pressures and relative evaporation rates. The evaporation rate indicates the rate of VOC emissions relative to each compound. For example, ethanol evaporates three times faster than iso-butanol at constant temperature, pressure, and humidity. Coating mixtures contain a number of these solvents and vary with each operation (filling, sealing, base coating, topcoating) and plant. The VOC emissions from each operation and plant therefore vary widely in mass rate per unit production, in mass rate per unit weight of coating used, and in concentration. In addition, the distribution of solvent emissions from solvent mixing, handling, and application (workroom emissions exhausted through roof vents and windows), and from drying ovens (point sources) can vary widely. For example, a plant that uses highly volatile solvents such as methanol, ethanol, and methyl ethyl ketone will emit much greater amounts of VOC through roof vents and windows (say 70 percent) than through drying oven exhaust (say 30 percent). In contrast, a plant that uses relatively low-volatility solvents such as amyl acetate, butanol, and VM and P naphtha will emit much less VOC from handling, mixing, and application (say 20 percent) than from drying oven exhaust (say 80 percent). The first example is probably the more typical.

3.9.2.4 Summary--

Table 3.9-3 presents estimates of potential VOC emissions from each operation using conventional coatings.[9] At plants applying filler, sealer,

TABLE 3.9-1. VOC CONTENT OF CONVENTIONAL FLAT WOOD COATINGS[a]

Paint type	Number of companies	Density, kg/liter	Density, (lb/gal)	Volatile organics, weight percent
Filler	4	1.7	(14.5)	15 - 30
Sealer	3	1.1	(9)	15 - 50
Base coat	7	1.4	(11.5)	40 - 75
Grain ink	6	1.2	(10)	30 - 70
Topcoat	8	1.1	(8.8)	50 - 75

[a] Source: Miscellaneous paint companies and Mr. Martin Kay, South Coast Air Quality Management District California. Reference 7.

TABLE 3.9-2. SOLVENTS USED IN COATINGS AND THEIR VAPOR PRESSURE AND EVAPORATION RATE[8]

Compound	Vapor pressure, at 20°C, mm Hg	Evaporation rate[a]
Butanol, iso	8.8	0.63
Butanol, n	4.4	0.46
Butanol, sec	12.7	0.90
Ethanol, anhydrous	44.0	1.9
Propanol, anhydrous	31.2	1.7
Methanol	96.0	3.5
Methyl ethyl ketone	70.6	4.6
Methyl isobutyl ketone	16.0	1.6
Toluene	38.0	1.5
Xylene	9.5	0.75
Butyl acetate, sec	4.0	1.9
Butyl acetate, iso	12.5	1.45
Butyl acetate, n	7.8	1.0
VM and P naphtha	2.0	0.45
Amyl acetate (primary)	4.0	0.4
Glycols	<0.01	
Glycol ethers	<1.0	<0.01

[a] Relative to that of butyl acetate, 1.0.

TABLE 3.9-3. POTENTIAL VOC EMISSIONS FROM FLAT WOOD OPERATIONS USING CONVENTIONAL COATINGS

	Range of VOC emissions[a],		Coverage[b],		Range of VOC emissions	
Operation coating	kg/liter coating	lb/gal coating	liters/ $10^3 m^2$	(gal/10^3ft)	g/m^2 coated	lb/10^3ft^2
Filler	0.26 - 0.53	(2.2 - 4.4)	119	(1.7)	31 - 62	(3.7 - 7.5)
Sealer	0.17 - 0.54	(1.4 - 4.5)	21	(0.3)	3.6 - 11.3	(0.4 - 1.4)
Base coat	0.44 - 1.0	(3.7 - 8.6)	56	(0.8)	25 - 56	(3.0 - 6.9)
Grain ink	0.36 - 0.84	(3.0 - 7.0)	7	(0.1)	2.5 - 5.9	(0.3 - 0.7)
Topcoat	0.53 - 0.79	(4.4 - 6.6)	49	(0.7)	26 - 38.7	(3.1 - 4.6)
				Total	88 - 174	(11 - 21)

[a] Table 3.9-1 presents typical VOC contents.

[b] Paint coverage information is from Reference 10.

base coat, grain ink, and topcoat, the estimated VOC emission factor may range from 88 to 174 g/km^2 (11 to 21 lb/1000 ft^2) of flat wood coated.

Because the volatile fraction of the coatings contributes essentially 100 percent of the VOC emissions, the total emissions from a plant are essentially the product of the weight fraction of volatile organics in the coatings and coating usage. Composition of the VOC emissions depends upon the types of solvents used. Exhausts from the ovens release practically all of the incoming volatile compounds, and the fraction of total plant emissions that comes from the dryer ovens depends on the types of solvents used, or more specifically their relative volatility or evaporation rate. Apparently no emission test data are available.

3.9.3 Control Measures

Technology for reduction of VOC emissions from flat wood operations includes use of low-solvent, ultraviolet-curable coatings; waterborne coatings; and incinerators. Generally, adsorption or add-on control devices other than incinerators are not considered feasible or demonstrated technology.[11] High-solids coatings are not practical for current use; however, their use as fillers and sealers has been demonstrated and may be further developed.[12] Electron-beam (EB) curing systems may have potential application for some product lines; however, only one commercial facility in the United States has installed such a system.[13,14]

3.9.3.1 Incineration--

The use of add-on control devices such as direct-flame and catalytic incinerators (afterburners) is very limited in the flat wood industry. Two plants, both in southern California, operate afterburners, but one has petitioned to stop operations of the burner because they are using Rule 66-approved solvents. Data are not available on control efficiency or fuel requirements at that plant.[15] The afterburner at the second plant has been tested several times, but it has not met control efficiency requirements.[16]

No adsorption system is known to be used in the flat wood industry. Use of multicomponent solvents and the use of different coating formulations at various steps along the coating line are not conducive to the application of adsorption techniques for emission control. Specific applications may be found in redwood surface treatment facilities, where over 90 percent of the coating is volatile and can be recycled by carbon adsorption.[11]

3.9.3.2 Waterborne Coatings--

The primary emission reduction technique used in the flat wood industry is conversion from conventional high-solvent coatings to waterborne coatings. Paint manufacturers have developed and are continuing to develop waterborne coating formulations to replace conventional coatings for many factory flat wood applications. The use of applicable waterborne coating in place of a conventional organic solvent-borne coating can reduce volatile organic emissions by at least 70 percent.[17] Table 3.9-4 presents typical values of volatile organics in conventional and waterborne coatings. Table 3.9-5 presents an estimate of VOC emissions in weight per area of surface covered.

Major changes are not required for use of waterborne coatings. The primary use of waterborne coatings is in the filler and base coat applied to printed interior paneling. Limited use has been made of waterborne materials for inks, groove coats, and topcoats on printed paneling, and for inks and groove coats on natural hardwood panels. Waterborne coatings can reduce fire hazards, fire insurance costs, and air pollution. Problems with waterborne coatings include possible grain raising, wood swelling, and poor quality finish.[17] A major complaint is that the waterborne coatings available to date require longer cure times.

3.9.3.3 Ultraviolet Curing[19]--

Ultraviolet-curable coatings, where applicable, effect almost 100 percent reduction of VOC emissions. In the flat wood industry, UV coatings have found use as clear to semitransparent fillers and topcoats for interior printed paneling and cabinetmaking products.

Ultraviolet-curable coatings are a combination of resin, prepolymers and monomers, and a photosensitizer (which serves as a catalyst). Polyester, acrylics, methane, and alkyds are common coating materials. Applied as a

TABLE 3.9-4. VOLATILE ORGANICS IN FLAT WOOD COATINGS[18]

Paint category	Paint type[a]	Density		Weight percent non-volatile	Typical VOC content[b]		VOC content (less water)		VOC reduction for equivalent coverage, %
		kg/ liter	(lb/gal)		kg/ liter	(lb/gal)	kg/ liter	(lb/gal)	
Filler	C	1.7	(14.5)	75	0.43	(3.6)	0.43	(3.6)	-
	W	1.7	(14.5)	75	0.05	(0.4)	0.07	(0.60)	90
Sealer	C	1.1	(9)	60	0.43	(3.6)	0.43	(3.2)	-
	W	1.1	(9)	55	0.12	(1.0)	0.23	(1.9)	70
Base coat	C	1.4	(11.5)	45	0.76	(6.3)	0.76	(6.3)	-
	W	1.4	(12)	55	0.08	(0.7)	0.19	(1.6)	90
Grain ink	C	1.2	(10)	40	0.72	(6.0)	0.72	(6.0)	-
	W	1.3	(10.5)	50	0.18	(1.5)	0.38	(3.2)	80
Topcoat	C	1.1	(8.8)	40	0.64	(5.3)	0.64	(5.3)	-
	W	1.1	(9)	45	0.17	(1.4)	0.32	(2.7)	80

[a] C = conventional paint with organic solvent.
W = waterborne, i.e., at least 80 percent of the volatile portion of the coating is water.

[b] Data received indicate that all companies providing information were able to meet the VOC content given for waterborne coatings.

TABLE 3.9-5. ESTIMATED[a] VOC EMISSIONS[18]

Paint	Coverage,[b] liters/$10^3 m^2$ (gal/1000 ft^2)		Potential VOC emissions, kg/100 m^2 coated (lb/1000 ft^2 coated)		
	Waterborne	Conventional	Waterborne	Conventional	UV[c]
Filler	112 (1.6)	119 (1.7)	0.3 (0.6)	3.0 (6.1)	nil
Sealer	25 (0.35)	21 (0.3)	0.2 (0.4)	0.54 (1.1)	0
Base coat	46 (0.65)	56 (0.8)	0.2 (0.5)	2.4 (5.0)	0.24 (0.5)
Print ink	7 (0.1)	7 (0.1)	0.1 (0.2)	0.3 (0.6)	0.1 (0.2)
Topcoat	46 (0.65)	49 (0.7)	0.4 (0.9)	1.8 (3.7)	nil
Total	236 (3.4)	252 (3.6)	1.2 (2.6)	8.0 (16.5)	0.4 (0.8)

[a] Table 3.20-4 presents typical VOC content.

[b] Paint coverage based on information from Reference 11. Adjustments made for waterborne and conventional paints are based on typical nonvolatiles content.

[c] UV line uses no sealer; uses waterborne base coat and ink. Total is adjusted to cover potential emissions from the UV coatings.

liquid, the coating is cross-linked and hardened on exposure to UV. The curing is extremely fast. Although there have been attempts to develop opaque UV coatings, none is yet available.

The advantages of UV coatings include reduced power requirements, space savings through reduced storage and oven size, very little emission of VOC, and the essentially 100 percent usable coating (since all components of the coating normally react and become part of the coating). Moreover, the short cure times can be measured in seconds, and a superior product results. Since little or no curing takes place after the panel leaves the oven, proper cure times must be carefully established. Safety precautions must be taken to minimize exposure to UV radiation and to avoid contact with the coating, as some of the raw materials can cause chemical burns.[20]

3.9.3.4 Electron Beam Curing--

One commercial facility in the United States uses an electron beam (EB) system. Opaque coatings can be cured to a depth of approximately 15 mils. Three to 5 mils of EB-cured coating produce a smooth, wear-resistant finish with performance comparable to that of many plastic laminates.[13,14] Although emissions from the system are still unknown, some airborne acrylics have been reported, and monomers and ozone emissions are possibilities.[13] Over 99 percent control of VOC is expected from EB systems.

3.9.3.5 Summary of Control Measures--

The highest reduction of VOC emissions, about 97 percent, can be achieved by use of UV-curable coatings. This control measure, however, can be only applied to certain products and operations. The use of waterborne coatings can achieve up to 90 percent reduction over conventional coatings, although use is limited somewhat by the necessity of maintaining acceptable surface and appearance quality. Incineration of dryer exhaust gases can reduce overall plant emissions by about 75 percent. At some installations incineration might also be used to control coating line emissions and provide an overall reduction of 95 percent or more. Electron beam curing can provide both a 99 percent control of VOC emissions and excellent surface finish quality. The major deterrent to its use is the highest of both the EB system and the costing materials.

3.9.4 Emission Limits

Review of State Implementation Plans (SIP) showed no VOC emission limitations specific to the flat wood industry. Rather, states have adopted general hydrocarbon emission regulations patterned after Los Angeles Rule 66. The South Coast Air Quality Management District Rule 442 (formerly Los Angeles Rule 66) places limitations on emissions from equipment using organic solvents or organic materials containing organic solvents. For organic materials that come into flame contact or are baked, heat-cured, or heat-polymerized the limitation is 1.4 kg (3.1 lb) per hour, not to exceed 6.5 kg (14.3 lb) per day. For organic materials emitted from use of photochemically reactive solvents, the limitation is 3.6 kg (7.9 lb) per day. For organic materials emitted from use of photochemically reactive solvents, the limitation is 3.6 kg (7.9 lb) per hour, not to exceed 18 kg (39.6 lb) per day if not in flame contact, baked, heat-cured, or heat-polymerized. The above-mass emission rate limitations do not apply if the emissions are reduced by at least 85 percent.

Recent research has indicated that substituting low-reactivity solvents for high-reactivity solvents may reduce photochemical oxidant levels locally while increasing them in downwind regions. Accordingly, EPA's current policy on VOC emissions emphasizes reduction of all hydrocarbons rather than substitution of exempt for nonexempt solvents.

The EPA has set no NSPS for this source category. It appears LAER will be determined by estimated reduction levels achieved in practice by use of waterborne coatings in combination with solvent-borne coatings.

3.9.5 Determination of LAER

The recommended limitations are based on SIP's and on performance information available in early 1979. It is anticipated that several additional SIP regulations covering these sources will be promulgated and/or modified in 1979 and 1980 and that appreciable new performance data will become available in the near term. Conceivably, some SIP regulations may be more stringent than the LAER suggested herein. Furthermore, performance testing mah show that more stringent limits than those suggested are feasible or it may show that the suggested limits are appropriate or that they are not achievable for some specific subcategories. In any case, the basis for determining LAER for many source categories is expected to change frequently. Since LAER is near the vanguard of control technology, a more detailed analysis is particularly necessary when addressing modified or reconstructed facilities subject to the provisions of Section 173 of the Clean Air Act. Emission limitations reasonable for new sources may in some instances be economically or technically unreasonable when applied to modified or reconstructed sources of the same type.

A study was made by EPA to determine the lowest emission levels being achieved by manufacturers of flat wood paneling.[21] Since no state regulations are more restrictive, the emission limitations recommended in this document are considered representative of LAER. Table 3.9-6 presents these limitations.

The recommended emission limits are stated in terms of kg of VOC per 100 m^2 of coated surface (lb per 1000 ft^2) to give operators necessary flexibility in adjusting the VOC content of the various coatings applied to a given panel. Because practices vary, it would be difficult to set a VOC limit for each type of coating. By balancing the VOC content and properties of the various coats, it is possible to achieve acceptable VOC reductions without sacrificing product quality.

TABLE 3.9-6. RECOMMENDED EMISSION LIMITATIONS FOR FACTORY-FINISHED PANELING

Product category	Recommended limitation	
	kg of VOC per 100 m^2 of coated surface	lb of VOC per 1000 ft^2 of coated surface
Printed interior wall panels made of hardwood plywood and thin particleboard	2.9	6.0
Natural-finish hardwood plywood panels	5.8	12.0
Class II-finished hardboard paneling	4.8	10.0

For printed interior panels, emission limits are based on partial use of waterborne and solvent-borne coatings. Waterborne coatings that produce acceptable quality are not available for all coatings, particularly clear topcoats and printing inks. For natural-finish paneling, the limits are based on use of solvent-based coatings of lower solvent content than conventional coatings. The number of coats and coverage of coatings vary, but (for typical usage) the recommended limitations are equivalent to usage of coatings that have average VOC contents of 0.20 kg/liter (1.7 lb/gal) for printed hardwood paneling, 0.38 kg/liter (3.2 lb/gal) for natural-finish paneling, and 0.32 kg/liter (2.7 lb/gal) for Class II-finish hardboard paneling.

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21. EPA 450/2-78-032, pp. iv-v.

3.10 MAJOR SOURCE CATEGORY: PETROLEUM LIQUIDS STORAGE-- VOLATILE ORGANIC COMPOUNDS (VOC) EMISSIONS

3.10.1 Process Description

In this report, petroleum liquids are defined as crude oil, condensate, and any finished or intermediate products manufactured or extracted in a petroleum refinery. These definitions are intended to apply to tanks with capacities greater than 150,000 liters (40,000 gallons) for the storage of petroleum liquid with a true vapor pressure greater than 10.5 kPa (1.5 psi).

The three major types of storage tanks for petroleum liquid are fixed-roof, external (open-top) floating-roof, and internal floating-roof. Figures 3.10-1, 3.10-2, and 3.10-3 are cross-sectional drawings of these tanks.

Fixed-roof tanks are generally cylindrical, with a conical roof permanently attached at the top. These tanks are commonly equipped with a pressure-vacuum vent that allows them to operate at a slight internal pressure or vacuum. The pressure-vacuum valves (vents) prevent release of vapors only during very small changes in temperature, pressure, or liquid level. These tanks are generally considered to represent the minimun acceptable standard for the storage of petroleum liquids.[1]

The external floating-roof tank has a steel cylindrical shell fitted with a deck or roof that floats on the liquid surface and rises and falls with the liquid level. The liquid surface is completely covered by the floating roof except in the small annular space between the roof and the tank shell. A seal attached to the roof contacts the tank shell and covers the annular space. The seal slides against the tank shell as the roof is raised or lowered.

Internal floating-roof tanks are fixed-roof tanks in which an internal roof or cover floats on the liquid surface. Operation is analagous to the external floating roof. The two kinds

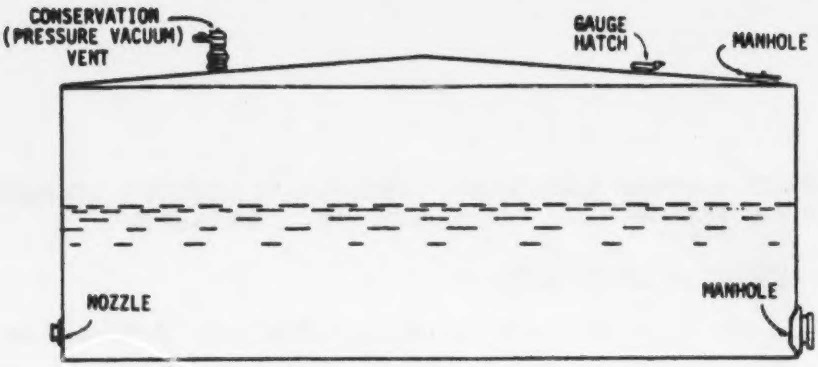
CONSERVATION (PRESSURE VACUUM) VENT
GAUGE HATCH
MANHOLE
NOZZLE
MANHOLE

Figure 3.10-1. Fixed-roof (cone-roof) storage tank.[2]

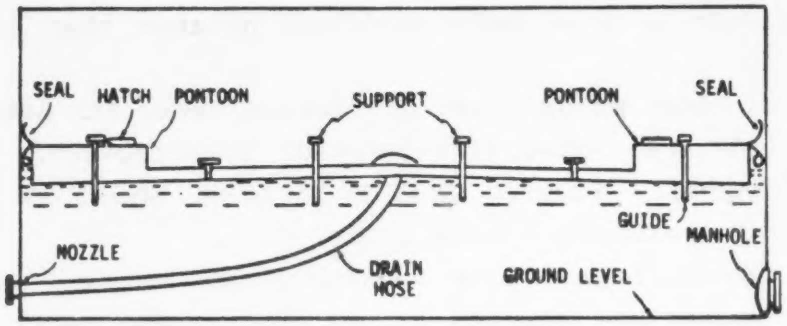
SEAL
HATCH
PONTOON
SUPPORT
PONTOON
SEAL
GUIDE
MANHOLE
NOZZLE
DRAIN HOSE
GROUND LEVEL

Figure 3.10-2. Single deck, external floating-roof storage tank.[2]

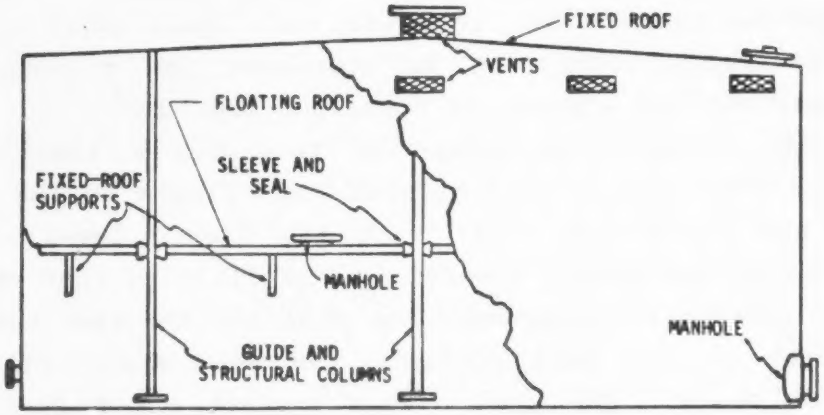
FIXED ROOF
VENTS
FLOATING ROOF
SLEEVE AND SEAL
FIXED-ROOF SUPPORTS
MANHOLE
MANHOLE
GUIDE AND STRUCTURAL COLUMNS

Figure 3.10-3. Covered floating-roof storage tank with internal floating cover.[2]

of internal covers commonly used are pan-type steel covers (known as covered floating roofs) and nonferrous (plastic or aluminum) covers (known as internal floating covers). The fixed roof shields the internal roof from weather effects and from structural damage or sinking due to accumulated rain or snow.

3.10.2 Emissions

VOC emissions from fixed-roof storage tanks are classified either as breathing losses or working losses. These losses occur when the working limit of the pressure-vacuum vent is exceeded. Breathing losses consist of vapors expelled from the tank because of the thermal expansion/contraction caused by diurnal temperature and barometric pressure changes.

Working losses consist of filling and emptying losses. Filling loss results from vapor displacement by the input of liquid. Emptying loss results from expulsion of vapor after product withdrawal and is attributable to vapor growth as the newly inhaled air becomes saturated with VOC.

Factors affecting the emission rate are the true vapor pressure (volatility) of the product stored, the temperature change (diurnal) in the tank vapor space, height of vapor space, tank diameter, schedule of emptying and filling, and mechanical condition of the tank.

Because its design dictates operation over a small pressure-vacuum range, the fixed-roof tank is subject to appreciable breathing and working losses. Pressure-vacuum valves restrict vapor release during small temperature-pressure fluctuations, but they allow venting during filling, emptying, and breathing.

The main source of emissions from external floating-roof tanks is attributable to wind-induced loss by the seal. Wind-induced emissions occur when the air flow across the tank creates pressure differences around the circumference of the floating roof and causes air to flow by the seal into the annular vapor space on the leeward side and air plus VOC to flow out on the windward side. Improper or loose fit of the seal can create gaps or openings between the seal and tank shell, which can cause increased wind-induced losses. Other VOC losses are associated with evaporation from the wetted wall after emptying and leakage of VOC vapor through the fabric cover that bridges the space between the shoe seal and floating roof.

Internal floating-roof tanks are usually equipped with special air vents in the fixed roof or at the top of the shell. These provide ventilation to minimize the possibility of VOC reaching the flammable range in the tank vapor space. Any VOC that flows by the seal because of wind-induced pressure differentials or by other seals in the floating cover escapes through these vents. The fixed roof reduces the wind-induced pressure differential around the seal, and emissions are lower than from external floating-roof tanks equipped with single seals.

Reference 3 presents formulas and tables of emission factors for calculating emissions from fixed-roof tanks, external floating-roof tanks, and internal floating-roof tanks. Because of the many variables that effect emissions from these tanks, it is recommended that these formulas be used to calculate emissions. For external floating-roof tanks with secondary seals and for all internal floating-roof tanks, standing storage losses are computed by using Equation (3), Section 4.3.2.2 of Reference 3, and then reducing that value by 75 percent (i.e. 25% Ls). No additional reduction is recognized at this time for secondary seals on internal floating roofs. The basic equations for calculating emissions from floating roof tanks are being revised by the American Petroleum Institute based on recently completed studies and tests. Appropriate revisions will be made to Reference 3 when this work is completed.

3.10.3 Control Measures

Besides improving air quality and eliminating (or at least reducing) safety (fire) hazards, the control of VOC emissions effects an economic savings through retention of valuable products. The most feasible and technically sound methods of control are floating roofs and vapor disposal systems.

3.10.3.1 External Floating-Roof Tanks--

External floating roofs virtually eliminate the vapor space above the stored liquid and essentially eliminate the working and breathing losses associated with fixed-roof tanks. The critical point is the sliding seal or closure covering the annular space between the tank wall and the roof. The seal is basically either a metallic shoe seal or a nonmetallic foam-filled or liquid-filled seal. Use of a primary (single) seal can be expected to reduce VOC emissions by more than 90 percent over uncontrolled (fixed-roof) tanks.

The metallic shoe seal is characterized by a 75 to 135 cm (30 to 51 in.) high long metal sheet held against the tank shell. The shoe is attached to the roof by braces and held against the wall by springs or weighted levers. A flexible, impervious fabric (envelope) from the top of the shoe seal to the roof top closes the annular space between the roof and the seal. The vapor space is restricted to the small area between the liquid surface and the envelope. (See Figure 3.10-4a).

Emissions occur from the exposed liquid surface of the gap spaces between the shoe and tank wall, and through openings in the envelope or shoe. The envelope and shoe conditions affect emissions since holes, tears, or other openings provide a direct path between the annular vapor space (bounded by the shoe liquid surface, envelope, and roof) and the atmosphere.

The nonmetallic seal, usually a flexible tube filled with resilient foam or liquid, is attached to the outer periphery of the floating roof and covers the annular space between the roof and shell (Figure 3.10-4, b-d). The liquid-filled seal is liquid-mounted and the foam-filled seal is either liquid-mounted or vapor-mounted. When the vapor-mounted seal is suspended

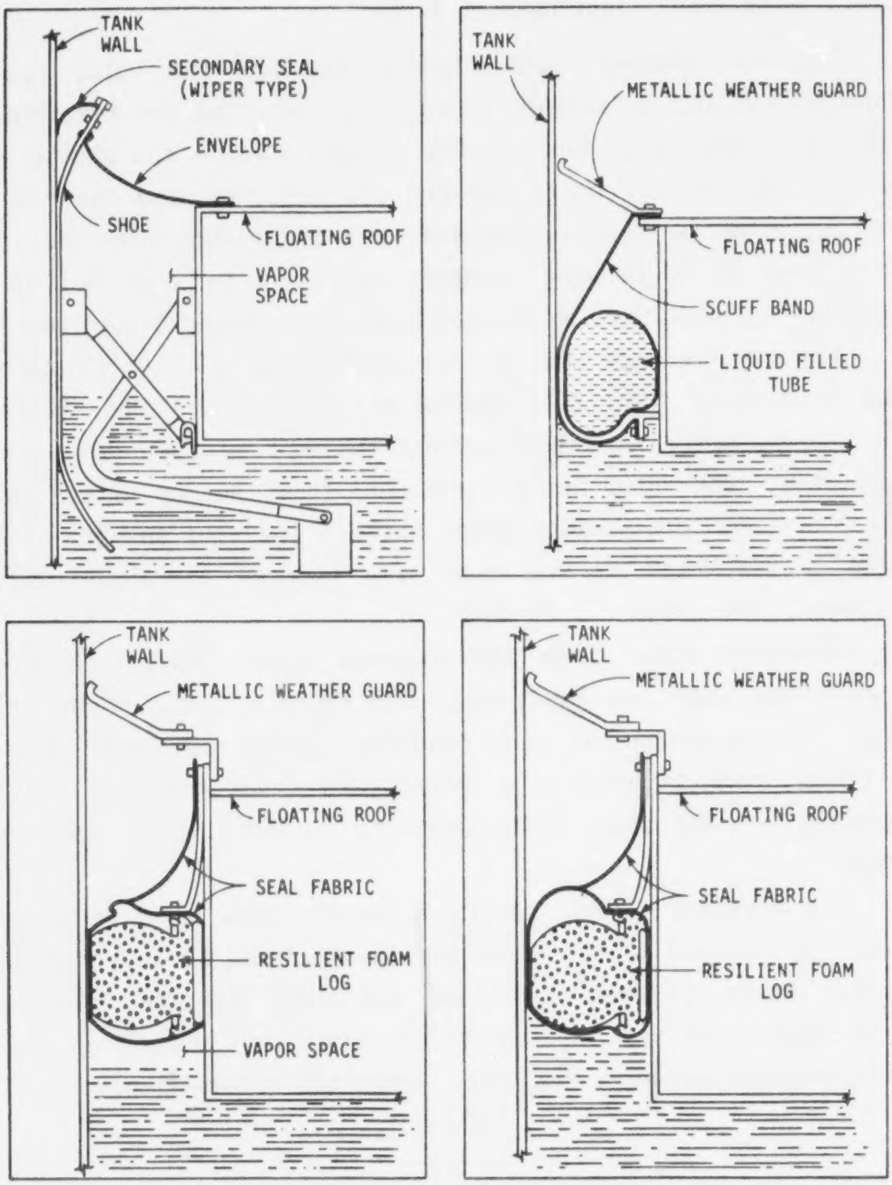
TANK WALL
SECONDARY SEAL (WIPER TYPE)
ENVELOPE
SHOE
FLOATING ROOF
VAPOR SPACE
TANK WALL
METALLIC WEATHER GUARD
FLOATING ROOF
SCUFF BAND
LIQUID FILLED TUBE
TANK WALL
METALLIC WEATHER GUARD
FLOATING ROOF
SEAL FABRIC
RESILIENT FOAM LOG
VAPOR SPACE
TANK WALL
METALLIC WEATHER GUARD
FLOATING ROOF
SEAL FABRIC
RESILIENT FOAM LOG

Figure 3.10-4. Primary seals.[4]

above the liquid surface, an annular vapor space (bounded by the tank shell, seal, roof, and liquid surface) exists and any gap between the seal and shell provides direct access of vapors to the atmosphere. Liquid-mounted seals rest on the liquid surface in the annular space between the shell and roof. Thus the annular vapor space is essentially eliminated. The fluid used in liquid seals should be compatible with the stored products to avoid contamination if the tube ruptured. Because of their flexibility, nonmetallic seals have some ability to adapt themselves to imperfections in tank walls, thereby reducing the gap space somewhat.

The use of a secondary seal that is located above and completely covers the primary seal can effectively control the VOC emissions that escape by the primary seal or through the shoe seal envelope. Two types of secondary seals are commonly installed--rim-mounted (Figure 3.10-5) and shoe-mounted (Figure 3.10-4a). The rim-mounted secondary seal is preferred since the shoe-mounted secondary seal does not provide protection against VOC leakage through the primary shoe seal envelope.

Wind-induced air flow around the primary seal system is the main cause of VOC losses through primary seals. Improper fit and leakage through the shoe seal envelope and shoe can also contribute to VOC emissions. Reference 4 states that rim-mounted secondary seals are effective in controlling emissions from liquid and vapor-mounted primary seals. The references cited as the basis for this statement are various industry sponsored test programs (Reference listings 5 through 10).

In reference 4 the reductions that would occur from installing secondary seals over primary seals have been calculated for various primary-secondary seal type combinations. The calculations indicate that the use of a tight fitting, rim-mounted secondary seal over primary seals effectively curtails emissions and that the quantity of emissions curbed increases as the true vapor pressure of the stored liquid increases.

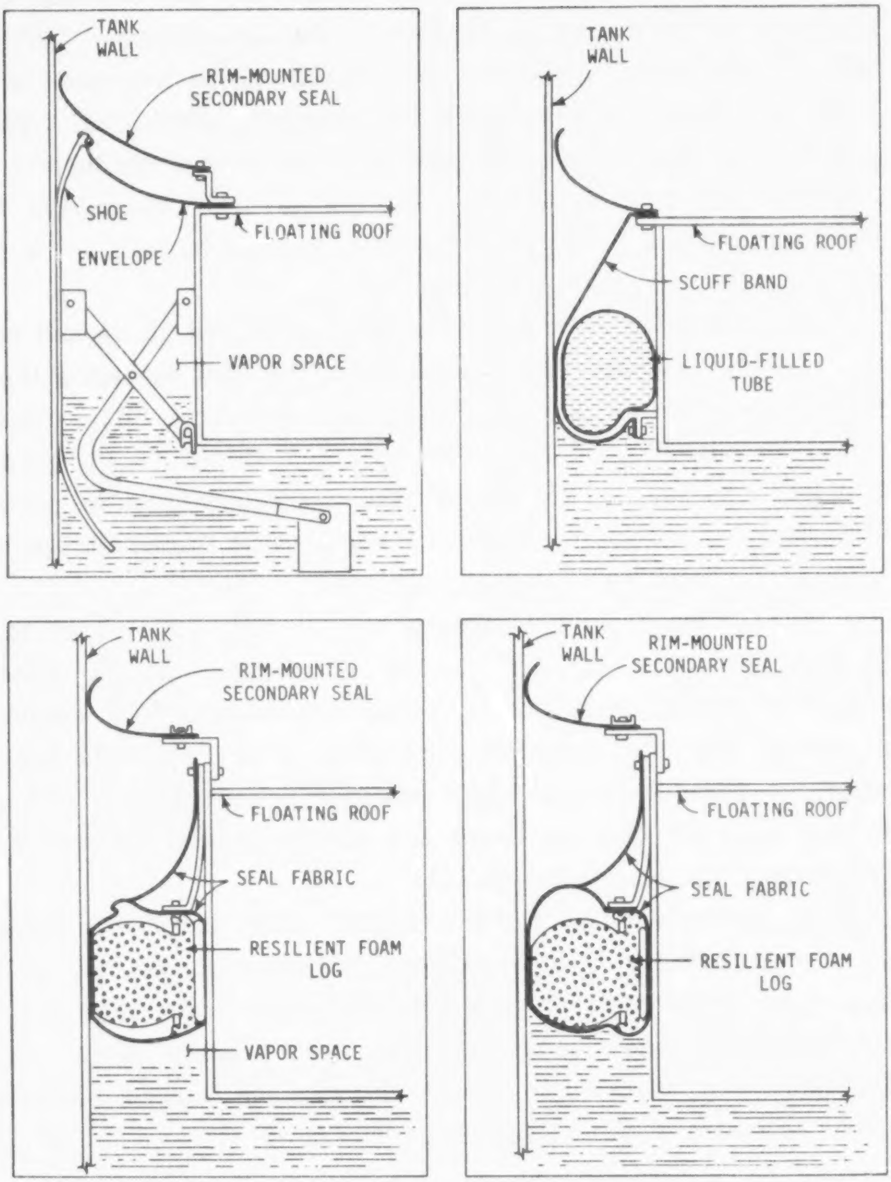
TANK WALL
RIM-MOUNTED SECONDARY SEAL
SHOE
ENVELOPE
FLOATING ROOF
VAPOR SPACE
TANK WALL
FLOATING ROOF
SCUFF BAND
LIQUID-FILLED TUBE
TANK WALL
RIM-MOUNTED SECONDARY SEAL
FLOATING ROOF
SEAL FABRIC
RESILIENT FOAM LOG
VAPOR SPACE
TANK WALL
RIM-MOUNTED SECONDARY SEAL
FLOATING ROOF
SEAL FABRIC
RESILIENT FOAM LOG

Figure 3.10-5. Rim-mounted secondary seals.[4]

3.10.3.2 Internal Floating Roof Tanks--

The internal floating-roof tanks described in 3.10.1 are currently considered equivalent to external floating-roof tanks equipped with secondary seals (as discussed in 3.10.3.1).

3.10.3.3 Vapor Recovery/Disposal Systems--

Two general types of these systems are used most frequently to effectively reduce emissions from fixed-roof storage tanks: systems that thermally destroy collected vapors (disposal) and systems that recover collected vapors as useful product (recovery). The thermal oxidizers (e.g., afterburners, flares) combust the vapors and result in emissions that are essentially water and carbon dioxide. The vapor recovery systems can employ compression, adsorption, refrigeration, and absorption principles to recover the VOC in the vapor as liquid product. Control efficiencies range from 85 to 98 percent, depending on the physical properties of the stored liquids and the design of the equipment.

Systems can be designed to collect, transport, and dispose of both working and breathing emissions from a series of interconnected tanks. Such systems should include the ability to isolate each tank and prevent vapor backflow from the entire system during sampling, gauging, or pressure change at an individual tank. Vapor recovery/disposal systems are most often found at gasoline marketing terminals; they have not been used extensively on large tanks or at tank farms. Figure 3.10-6 is a schematic layout of a hypothetical system.

3.10.4 Emission Limits

3.10.4.1 New Source Performance Standards--

Present NSPS require that storage vessels with capacities greater than 151,412 liters (40,000 gallons) containing petroleum liquid with a true vapor pressure greater than 10.5 kPa (1.5 psia) be equipped with an external or internal floating roof, a vapor recovery system (collection and disposal), or their equivalents. Tanks in which crude oil and condensate are stored before

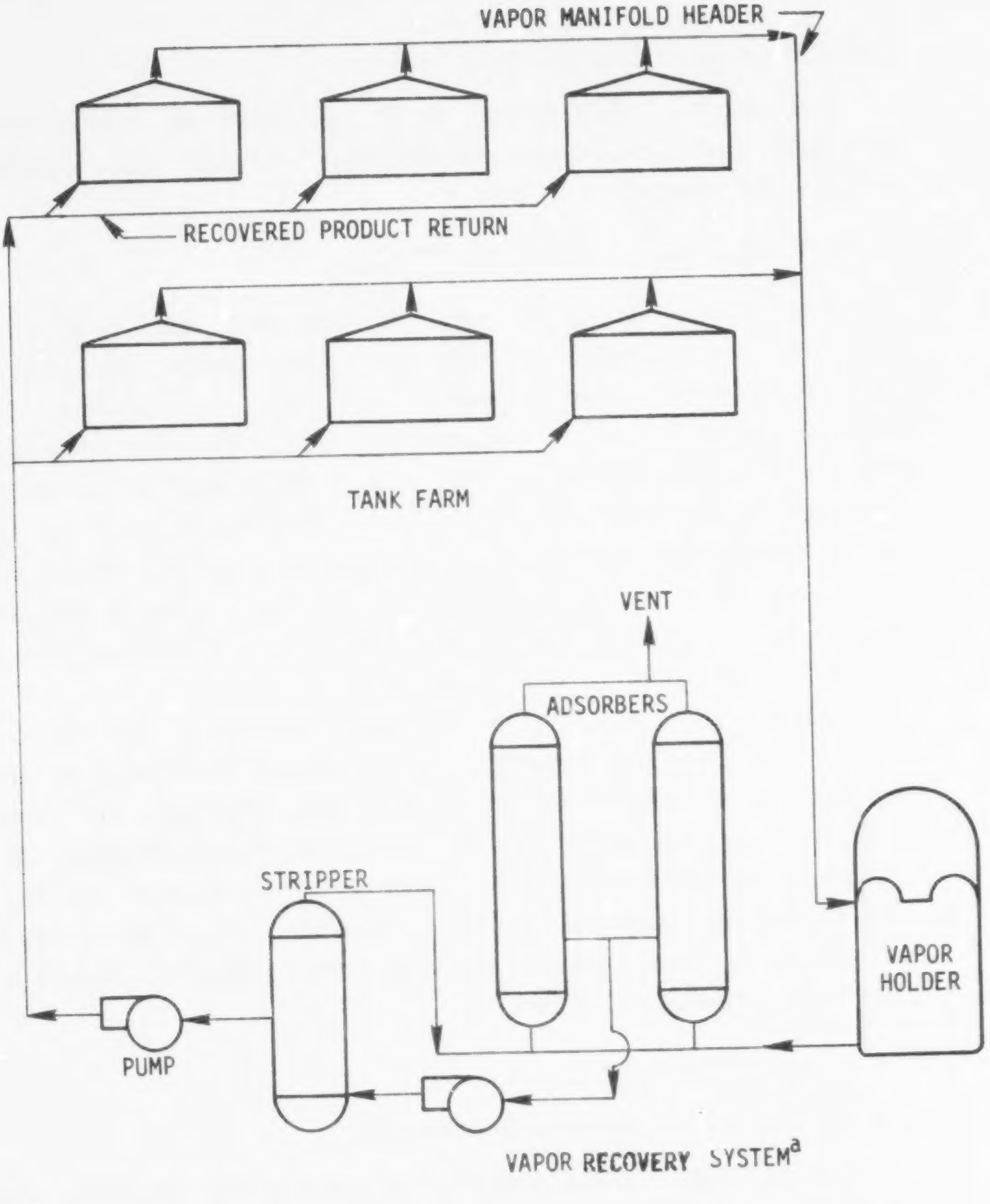
VAPOR MANIFOLD HEADER
RECOVERED PRODUCT RETURN
TANK FARM
VENT
ADSORBERS
STRIPPER
VAPOR HOLDER
PUMP
VAPOR RECOVERY SYSTEM[a]

Figure 3.10-6. General schematic of vapor recovery system.

[a] The principle, design, mode of operation, and components of systems vary. Systems principles generally include one or more of the following: adsorption, absorption, combustion, and refrigeration.

custody transfer are specifically exempted. A revised NSPS proposed in May 1978 has not yet been promulgated and is therefore not applicable until final promulgation. Since promulgation of the standard may occur in late 1979, the main features of the proposed standard are relevant and worthy of mention here. The proposed standards would require a floating roof; an external floating roof with double seals that meet specified gap limitations or a vapor recovery system; or the equivalent of either device. The exemption on crude oil and condensate tanks was removed. A final review of the comments received on the proposal and the most recent emission data is being completed. The promulgation will reflect changes to the proposal as a result of the final review.

3.10.4.2 State Implementation Plans--

The most stringent SIP requirement discovered was the South Coast (California) Air Quality Management District Regulation 463 (Storage of Organic Liquids). This SIP limitation requires floating roofs or vapor recovery systems (or the equivalent) for liquids of a true vapor pressure between 78 to 570 mm Hg (1.5 to 11.1 psia), inclusive, stored in tanks with a capacity greater than 150,000 liters (39,630 gal); double seals on external floating-roof tanks; specific allowable gaps between seal and tank wall in terms of width and percent of circumference; and internal floating-roof covers on fixed-roof tanks or vapor recovery/disposal systems of equal reduction efficiency.

3.10.5 Determination of LAER

The recommended limitations are based on SIP's and on performance information available in early 1979. It is anticipated that several additional SIP regulations covering these sources will be promulgated and/or modified in 1979 and 1980 and that appreciable new performance data will become available in the near term. Conceivably, some SIP regulations may be more stringent than the LAER suggested herein. Furthermore, performance testing may show that more stringent limits than those suggested are feasible or it may show that the suggested limits are appropriate or that they are not achievable for some specific subcategories. In any case, the basis for determining LAER for many source categories is expected to change frequently. Since LAER is near the vanguard of control technology, a more detailed analysis is particularly necessary when addressing modified or reconstructed facilities subject to the provisions of Section 173 of the Clean Air Act. Emission limitations reasonable for new sources may in some instances be economically or technically unreasonable when applied to modified or reconstructed sources of the same type.

The LAER recommendations below are intended for application to petroleum liquid storage tanks greater than 150,000 liters (40,000 gallons) containing petroleum liquids with a true vapor pressure greater than 10.5 kPa (1.5 psi). The suggested requirements are in the form of devices that contain and prevent emissions rather than a specified emission limit or rate.

The recommended LAER for petroleum liquids storage in external floating-roof tanks is the application of double-seal technology as briefly discussed in Section 3.10.3. (An expanded treatment of double-seal technology can be found in Reference 4.) Double-seal technology consists of a primary seal (either a metallic-type shoe seal; a liquid-mounted foam-filled seal; a liquid-mounted liquid-filled type seal; or another equally effective closure device) and a continuous secondary seal extending from the floating roof to the tank wall (a rim-mounted secondary). The seal closure devices should have no holes, tears, or other visible openings in the seal or seal fabric; should be intact; and have a uniform, tight fit between the roof and tank wall around the roof circumference. All openings in the roof, except rim space-vents should project below the liquid surface. Openings, except for rim space-vents, automatic bleeder vents, leg sleeves, and emergency drains, should be equipped with a cover or lid that is closed at all time except when in actual use.

The importance of minimizing the gap between the rim-mounted secondary seal and the tank wall in preventing VOC emissions is emphasized. At this time specific gap requirements have not been promulgated by EPA. It is suggested that the gap area specified in Reference 4, page 5-2, be used as an interim guide until more definitive requirements become available.

Reference 4 suggests that the gap area of gaps exceeding 0.32 cm (1/8 inch) in width between the secondary seal and the tank wall not exceed 6.5 cm^2 per 0.3 M of tank diameter (1.0 square inch per foot of tank diameter).

For fixed roof tanks, the recommended LAER is an internal floating-type cover with a single continuous closure device between the tank shell and the floating-cover edge.

Vapor recovery/disposal systems of equivalent VOC control capability can also be used to meet the LAER requirements, as can other systems that have satisfactorily demonstrated an equal reduction performance.

The reader is reminded that should the revised NSPS scheduled for promulgation in late-1979 contain any provisions more stringent than this LAER determination, then, under Section 171(3) of the Clean Air Act as Amended August 1977, these provisions of the NSPS would apply.

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3.11 MAJOR SOURCE CATEGORY: PETROLEUM REFINERIES--WASTEWATER SEPARATORS, PROCESS UNIT TURNAROUNDS, AND VACUUM PRODUCING SYSTEMS--VOLATILE ORGANIC COMPOUNDS (VOC).

3.11.1 Process Description

3.11.1.1 Wastewater Separators--

Petroleum refineries operate wastewater treatment facilities to meet standards for process effluent. The wastewater separator is the first stage of water treatment. Contaminated wastewater is collected from process drains, storm sewers, and equipment cleaning operations. Additionally, water from leaks, spills, pump and compressor sealing, flushing, and sampling may go into the wastewater system. Because rains can cause sudden surges in the volume of water handled, the storm sewer water is usually segregated and retained in a separate holding pond before treatment in the wastewater separator. The wastewater separator skims oil from the water and returns it to the process. The wastewater then undergoes additional treatment to meet effluent standards.

Refinery wastewater drains and treatment facilities can emit volatile organic compounds (VOC) by evaporation. Volatile organics may be emitted at any place that wastewater is exposed to the atmosphere. Sealing sewer openings by the use of liquid traps or other devices minimizes VOC emissions. Refinery operators have used such sealing devices for many years because of the safety hazard associated with hydrocarbon-air mixtures.

Wastewater separators, the most common of which are API separators, are possibly the largest source of VOC emissions from wastewater treatment. An API separator is a gravity differential device consisting of a series of baffles and weirs in a container operated at atmospheric pressure. Because the input is by gravity flow from an underground sewer, the tank or container is underground. Although early practice did not include covering of these tanks, some refiners now cover the forebays of API separators to control VOC emissions and a few cover the entire separator area.

3.11.1.2 Process Unit Turnarounds--

Periodic process unit turnarounds are required to ensure safe and efficient operation of equipment. Insurance requirements, safety regulations, and industry standards require periodic inspection and maintenance of all vessels. Thus, process unit turnarounds are an essential operation in a refinery.

A turnaround entails emptying the equipment for inspection and maintenance. A typical procedure involves draining the liquids from the vessel; depressuring the vessel; flushing the vessel with water, steam, or inert gases to remove all hydrocarbons; and then air blowing to provide oxygen for breathing. The operations provide many opportunities for VOC emissions to the atmosphere. The vapor content of vessels is usually vented to a flare system, through a furnace firebox, to a vapor recovery system, or directly to the atmosphere, depending on operating practice and refinery configuration.

3.11.1.3 Vacuum-Producing Systems--

Use of vacuum-producing systems is principally at vacuum towers for distillation of the very high-boiling components of crude oil from residuum fractions. Other uses include evacuation of processing equipment for maintenance and for removing noncondensables from condensers that process steam from turbines.

This separation of high-boiling fractions (340° to 566°C or 650° to 1050°F gas oils) from residuum is required because it renders the gas oils more valuable for subsequent processing. Separation is accomplished by distillation under vacuum because the oil will crack at temperatures required to distill it under atmospheric pressure. Distillation under vacuum greatly increases the overall yield of gas oil fractions of the crude oil.

Distillation involves heating the so-called reduced crude oil to about 400°C (750°F) and sending it to a tower operated under vacuum. The flash zone at which the vapors and residuum are separated typically operates above 370°C (700°F) and at absolute pressures of 1.3 to 16 kPa (10 to 120 mm Hg). Instruments on the vacuum-producing system control the flash zone pressure and, indirectly, the pressure at the top of the tower. Effective pressure in the flash zone may be further reduced by introduction of steam with the feed or at the bottom of the tower, the latter providing a stripping action on the residuum product before it leaves the bottom of the tower.

The vapor portion of the feed flows upward through an entrainment removal section and then through distillation trays, which intimately mix the vapors with cooled heavy-vacuum gas oil pumped back into the tower at a higher level as reflux and as cooling fluid. The remaining vapors then proceed through a similar section with light-vacuum gas oil as reflux and coolant. The vapors that leave the top of the tower are exhausted by the vacuum-producing system.

The basic types of vacuum-producing systems are ejectors and mechanical pumps (compressors). An ejector system is a gas compressor that uses the high-pressure energy of one fluid to compress another. The high-pressure fluid is almost always steam, which is "jetted" from a nozzle through a vacuum chamber at high velocity, entraining the vapors from the tower. The steam from the ejector is then condensed by contact with water (either directly or through tubes of a water cooler) or by an air cooler. The noncondensables are vented to the atmosphere, to another stage of jet ejection, or to a blower. The vacuum towers in oil refineries usually require three ejectors in series.

For the large ejector systems required on large vacuum units, the steam is condensed and the gas is cooled. The resultant mixture of water, hydrocarbons, and dissolved gases is sent to a ground-level accumulator called a "hotwell." Water from the hotwell requires treatment to remove oil, and vapors from the hotwell may require containment and disposal. Use of a surface condenser, either water- or air-cooled, greatly decreases the volume of water that must be treated, because the cooling water is not contaminated with hydrocarbons.

Although refineries use steam ejectors almost exclusively because of their initial low cost, lack of moving parts, operating simplicity, and reliability, vacuum pumps also can produce the necessary vacuum. Such pumps are being considered more and more because of increasing concern with water pollution and because of rising energy costs, which favor pumps over the very thermally inefficient steam ejectors. No refinery is known to have installed vacuum pumps. They are particularly expensive for use at very low vacuums below 50 mm Hg absolute pressure. Although the fuel savings offered by vacuum pumps is substantial,[1] the pumps are much less reliable than steam injectors and cost much more to install and maintain. It is anticipated that serious consideration will be given to vacuum pumps for application to new vacuum towers on the basis of energy cost savings.

3.11.2 Emissions

3.11.2.1 Wastewater Separators--

Because the VOC at wastewater separators come from many refinery sources served by the collection system, volatility of the compounds emitted ranges widely. Typically, the compounds include C_1 to C_8 paraffins, olefins and aromatics, hydrogen, hydrogen sulfide, and ammonia. None of the data adequately quantified emissions from wastewater separators, although it is estimated that the emissions from uncovered wastewater separators can be large.

3.11.2.2 Process Unit Turnarounds--

Potential emissions from turnarounds include the full range of hydrocarbons in a refinery. Emissions also may include hydrogen, ammonia, carbon monoxide, hydrogen sulfide, sulfur oxides, and particulates.

3.11.2.3 Vacuum-Producing Systems--

The barometric condenser hotwell accumulators and the last stage of the steam ejector system emit light, noncondensed hydrocarbon compounds (VOC), which would generally include hydrogen, methane, ethane, propane, butanes, pentanes, and hydrogen sulfide, together with low concentrations of olefins and uncondensed gases (nitrogen, oxygen, and CO_2).

3.11.3 Control Measures

3.11.3.1 Wastewater Separators--

Volatile organic emissions from wastewater separators can be reduced and well controlled by covering the separators and all openings to enclose completely the liquid contents. A floating cover equipped with closure seals between the edges of the cover and the separator can minimize VOC emissions. Use of separator covers and liquid trap seals for sewer drains should minimize VOC emissions from wastewater systems.

3.11.3.2 Process Unit Turnarounds--

Control of VOC emissions during process unit turnarounds starts with the pumping of liquid contents from the process unit to storage. This operation now involves enough economic incentive for complete compliance to be anticipated. Collecting the vapors from the depressuring of vessels is the next most effective step. The purged vapors along with vapors forced from the system by flushing of the process unit with water, steam, or inert gas can be directed to a vapor control system, to a flare header system, or to a firebox for incineration.

3.11.3.3 Vacuum-Producing Systems--

Vapors from the last stage of a vacuum-producing system and from the hotwell can be collected and sent to a furnace firebox or to a vapor recovery unit with the assistance of a mechanical blower (compressor). Both recovery and use-as-fuel systems provide incentives related to the concern with air quality and energy costs and the trend to larger vacuum units in refineries.

3.11.4 Emission Limits

No New Source Performance Standards (NSPS) have been promulgated for wastewater separators, process turnarounds, or vacuum-producing systems at refineries, nor is information available upon which to base an achieved-in-practice emission limit.

3.11.4.1 State Implementation Plan (SIP) Limits--

Specific regulations applicable to vacuum-producing systems and wastewater separators are embodied in California's South Coast Basin rules; these are the most restrictive found in any SIP. No regulation specific to process unit turnarounds was found.

Under Rule 465 of the California South Coast Air Quality Management District (SCAQMD), the discharge from vacuum-producing devices is limited to no more than 1.36 kg (3.0 lb) of organic materials in any 1 hour from any vacuum-producing devices or systems, including hotwells and accumulators, unless such discharge has been reduced by at least 90 percent. In other areas of the country VOC emissions are limited under a general rather than a source-specific regulation. For example, the Bay Area Air Pollution Control District, San Francisco, California, (Regulation 3101) states "....a person shall not discharge into the atmosphere an effluent containing a concentration of more than 50 ppm or organic compounds calculated as hexane (or 300 ppm total carbon)."

Wastewater separators are addressed specifically in SCAQMD Rule 464 of the California South Coast Basin, which states that a person shall not use any compartment of any vessel or device operated for the recovery of oil from effluent water, unless such compartment is equipped with one of the following vapor-loss control devices:

a. A solid cover on which all openings are sealed, thereby totally enclosing the liquid contents of the compartment.

b. A floating pontoon or double-deck type cover equipped with closure seals between the cover's edge and the compartment wall. [Gaps between the compartment wall and seal are limited to 0.32 cm (1/8 in.) for an accumulative length of 97 percent of tank perimeter, and are not to exceed 1.3 cm (1/2 in.) for an accumulative length of the remaining 3 percent of tank perimeter. No gap is to exceed 1.3 cm (1/2 in.) in width.]

c. A vapor recovery system that reduces the emission of all hydrocarbon vapors and gases into the atmosphere by at least 90 percent by weight.

d. Other equipment having an efficiency equal to or greater than a, b, or c (listed above) and approved by the Air Pollution Control Officer.

3.11.5 Determination of LAER; Controls to Achieve LAER

3.11.5.1 Wastewater Separators--

In the absence of achieved-in-practice data and NSPS, the lowest achievable emission rate is determined to be that degree of VOC emission reduction required by the South Coast Air Quality Management District Rule 464 (see Section 3.11.4.1). The LAER is therefore a vapor-recovery system that reduces all VOC by at least 90 percent by weight, or certain specified equipment, or other equipment of equal or greater control efficiency. Control equipment includes the covering of separators, forebays, and other openings with seal-equipped floating roofs; use of liquid trap seals for sewer drains; and a monitoring and inspection program to detect any excessive VOC releases to the drainage system.

3.11.5.2 Process Unit Turnarounds--

LAER for process unit turnarounds is that emission rate resulting from collecting and subsequently either incinerating or recovering the vapors released during the depressuring and purging of process units. It is estimated that LAER is an overall reduction of 90 percent by weight or greater in potential emissions from the turnaround process. A piping system would be required to convey the VOC emissions to the control device.

3.11.5.3 Vacuum-Producing Systems--

The recommended limitations are based on SIP's and on performance information available in early 1979. It is anticipated that several additional SIP regulations covering these sources will be promulgated and/or modified in 1979 and 1980 and that appreciable new performance data will become available in the near term. Conceivably, some SIP regulations may be more stringent than the LAER suggested herein. Furthermore, performance testing may show that more stringent limits than those suggested are feasible or it may show that the suggested limits are appropriate or that they are not achievable for some specific subcategories. In any case, the basis for determining LAER for many source categories is expected to change frequently. Since LAER is near the vanguard of control technology, a more detailed analysis is particularly necessary when addressing modified or reconstructed facilities subject to the provisions of Section 173 of the Clean Air Act. Emission limitations reasonable for new sources may in some instances be economically or technically unreasonable when applied to modified or reconstructed sources of the same type.

LAER for vacuum-producing systems is a 90 percent by weight reduction of the VOC emissions from the last stage of the system and the associated hotwell. This reduction anticipates effective capture, collection, and transport of VOC to the control unit by the collection system. Available controls to achieve LAER include an effective collection system and vapor disposal by either incineration (e.g., a furnace firebox) or vapor recovery.

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3.12 MAJOR SOURCE CATEGORY: PETROLEUM REFINERIES--FUGITIVE EMISSIONS--VOLATILE ORGANIC COMPOUNDS (VOC)

3.12.1 Process Description

Equipment leaks provide numerous sources of fugitive volatile organic compound (VOC) emissions in petroleum refineries. Among the equipment items that are subject to leaks are pump and compressor seals, valve stems and bonnets, flanges, pressure-relief devices, process drains, sample valves, and other open-end valves.

The proper mating of two sealing surfaces is essential if pump seals, compressor seals, valve stem seals, valve seats, bonnets, flanges, and other connections are to maintain their sealing ability. These sealing surfaces are sometimes finely machined surfaces and sometimes compressed packing (gaskets). Proper design and maintenance are required to minimize leakage.

Properly seated pressure relief devices will provide a good seal until they have been opened and closed several times and foreign matter (such as corrosion products, carbon particles, and gum) collects on the seats, after which the seal may no longer be free of leaks.

The open-end valves used for sampling and bleeding lines become a source of fugitive emissions if they are not completely closed or are not seating properly.

3.12.2 Emissions

Although a wide range of volatile organic compounds is emitted as a result of equipment leaks, most are hydrocarbons with one to six carbon atoms, such as olefins, paraffins, and aromatics. Their composition depends on the kinds of crude oil processed in the refinery, the complexity of the refining process, and the specific processing units involved. The volume of pollutants emitted depends on these same items in addition to maintenance practices and refinery age.

Available data regarding emissions from fugitive sources are limited, and EPA is currently conducting studies to quantify these emissions. Data regarding leak rates and VOC emissions for fugitive refinery sources recently became available as a result of one such study.[1] These are presented in Table 3.12-1, which indicates the percentage of all sources of a given type that exhibited leaks (estimated percent leaking) and the average VOC emissions from those that were leaking (emission factor estimate). The data were derived from studies at nine refineries (large and small, new and old) and from an examination of 500 to 600 sources at each of the refineries studied.

3.12.3 Control Measures

Many design and operational measures are available for reduction of emissions at petroleum refineries. A well planned and executed monitoring and maintenance program is one of the most effective methods. For many years refineries have used such programs to prevent the formation of vapor clouds and to eliminate the possibility of explosion; however, only recently have refiners used portable flame ionization detectors and other analytical instruments to determine total hydrocarbon levels near major process equipment. Analytical instruments capable of measuring hydrocarbon concentrations in a range from 1 or 2 to several thousand parts per million are necessary for this type monitoring.

Because fugitive emissions at pump seals, compressor seals, and valve stems occur at random and cannot be predicted, a periodic walk-through inspection and monitoring program are required to detect leaks if emissions are to be reduced significantly. Although initially expensive, a properly designed and permanent monitoring system would serve to discover, relay to, and alert refinery personnel to the presence of VOC and the need for corrective action.

TABLE 3.12-1. ESTIMATED EMISSION FACTORS FOR SELECTED PETROLEUM REFINERY VOC SOURCES[a]

Source type	Estimated percent leaking[b]	Emission factor estimate[c],	
		g/h per source	(lb/h per source)
Valves			
Gas/vapor service[d]	29.3	21.0	(0.047)
Light liquid/two-phase service[d]	36.5	10.0	(0.023)
Heavy liquid service[d]	6.7	0.3	(0.0007)
Pump seals			
Light liquid service	63.8	118.0	(0.26)
Heavy liquid service	22.6	20.0	(0.045)
Compressor seals			
Hydrocarbon service	70.3	440.0	(0.98)
Flanges	3.1	0.26	(0.00058)
Drains	19.2	32.0	(0.07)
Relief valves	39.2	86.0	(0.19)

[a] Adapted from Table 1-1, p. 2, Reference 1.

[b] Estimate of percent of total sources found to be leaking. A leaking source is defined as a source with measured leakage values equal to or greater than 200 ppmv or sources with measured leak rates greater than 0.00454 g/h (0.00001 lb/h).

[c] Emission factor estimate for leaking sources only, i.e., those found to leak as defined in "a" above.

[d] Gas/vapor service means the hydrocarbon stream was a vapor at process conditions; light liquid means a liquid lighter than kerosene; liquid means a liquid equal to or heavier than kerosene.

Design changes that can reduce fugitive emissions at new facilities include pumps and compressors equipped with fluid-flushed, double mechanical seals and a vapor collection and recovery system. (Pumps with double seals and various kinds of flushing fluids are currently used by refineries when handling toxic fluids.) Other design changes include enclosures around flanges and the use of double pipes; however, the high initial cost and even higher maintenance costs render both impractical.

3.12.4 Emission Limits

No New Source Performance Standards (NSPS) limits apply to fugitive emissions from refineries, and Achieved in Practice (AIP) limits have not been adequately quantified.

3.12.2.1 State Implementation Plan (SIP) Limits--

In many states VOC emission regulations require that all persons use reasonable care to avoid discharge, leaking, spilling, seeping, pouring, or dumping of compounds, or that they use known and existing vapor control emission devices or systems.

California's South Coast Air Quality Management District (SCAQMD) Rule No. 466 (adopted May 7, 1976, and amended September 2, 1977) prohibits the use of any pump or compressor to handle organic materials with a Reid vapor pressure of 80 mm mercury (1.55 lb/in.^{2}) or greater unless such pump or compressor is equipped with a mechanical seal in good working order or some other device of equal or greater efficiency and approved by the Executive Officer. The rule specified that mechanical seals be maintained so that there is (1) no leakage greater than three drops per minute, (2) no visible mist from liquid being pumped where such liquids do not condense at ambient conditions, and (3) no visible indication of leakage evident at or near the seal/shaft interface of gas compressors. An inspection for visible leaks at pumps and compressors is required once every 8-hour period unless the refinery is located more than 3 miles from a continuously manned control center. In this case an inspection is required once every 24 hours.

SCAQMD Rule No. 467 (adopted May 7, 1976) prohibits the use of any safety pressure relief valve on any equipment that handles organic materials with an absolute pressure of more than 776 mm mercury (15 lb/in.^{2}) unless the relief valve is vented to a vapor recovery or disposal system, is protected by a rupture disc, or is maintained by an inspection system approved by the Air Pollution Control Officer. SCAQMD Rule No. 466.1 (adopted November 3, 1978) pertains to valves and flanges. The general requirements are record keeping, periodic leak inspection, leak repair within 2 days (some exceptions allow a greater repair time), and the use of a seal (cap, plug, or flange) on each valve at the end of a pipe or line containing VOC when the line is not in use (certain valves exempted).

3.12.5 Determination of LAER

The recommended limitations are based on SIP's and on performance information available in early 1979. It is anticipated that several additional SIP regulations covering these sources will be promulgated and/or modified in 1979 and 1980 and that appreciable new performance data will become available in the near term. Conceivably, some SIP regulations may be more stringent than the LAER suggested herein. Furthermore, performance testing may show that more stringent limits than those suggested are feasible or it may show that the suggested limits are appropriate or that they are not achievable for some specific subcategories. In any case, the basis for determining LAER for many source categories is expected to change frequently. Since LAER is near the vanguard of control technology, a more detailed analysis is particularly necessary when addressing modified or reconstructed facilities subject to the provisions of Section 173 of the Clean Air Act. Emission limitations reasonable for new sources may in some instances be economically or technically unreasonable when applied to modified or reconstructed sources of the same type.

The complexity of processing units used in refineries varies, depending on the different crude oils processed and products produced. These differences among refineries and refinery operations and the fact that fugitive emissions occur randomly, originate from numerous sources, and are not precisely quantified, make it difficult to establish an acceptable national standard for limiting mass emissions.

The lowest achievable emission rate (LAER) for fugitive VOC emissions at petroleum refineries is therefore determined to be the emission rate that occurs after equipment designed to minimize emissions has been properly installed and a program of practical housekeeping, monitoring, routine inspection, preventive maintenance, and equipment repair/replacement has been established. Where technically feasible, pumps and compressors should have double mechanical seals that are fluid-flushed, and the flushing fluid facilities should be equipped with a vapor collection/recovery system. Certain types of compressors can be equipped with appropriate purge systems. The provisions of California's SCAQDM Rule 466 (see 3.14.4) in regard to inspection schedule, leakage rate, and visible emissions are considered applicable as LAER guidelines for pumps and compressors. The inspection-maintenance program should include a periodic walk-through inspection using visual techniques and, where appropriate, be supplemented by hydrocarbon detection equipment to provide early detection of existing or developing leaks. Particular attention should be directed to pipeline valves, sampling equipment, and pressure relief valves. All leaking or defective components should command early attention and be isolated and repaired or replaced to protect air quality and safety.

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3.13 MAJOR SOURCE CATEGORY: GRAPHIC ARTS PRINTING--VOC EMISSIONS

In 1970 there were more than 40,000 printing and publishing establishments in the United States.[1] Total solvent usage in this industry in 1976 was estimated at 340 Gg (380,000 tons).[2] With an overall degree of emission control estimated at 30 percent, the total of national organic compound emissions was estimated at 240 Gg (270,000 tons). The approximate contributions of each major graphic arts process are gravure, 41 percent; lithography, 28 percent; letterpress, 18 percent; and flexography, 13 percent.[2]

3.13.1 Process Descriptions

High-volume printing operations utilize rotary presses in which the image carrier is curved and mounted on a rotating cylinder. In gravure, the image cylinder rotates in the ink trough (ink fountain). In other processes a second cylinder rotates in an ink trough and delivers ink to the plate cylinder (image), usually through a series of distribution rollers. In direct printing operations, the image carrier transfers the image directly to the print surface. In offset printing operations, an intermediate surface transfers the image to the print surface.

Printing methods are classified by the principles upon which the printing image carriers are based. Two types are discussed herein: rotogravure and flexography.

Printing presses are fed by sheet or roll paper. Roll-fed operations require dryers to evaporate the solvent from the ink. Dryers are high-velocity hot-air dryers, direct-flame dryers, or indirect steam-heated dryers.

3.13.1.1 Rotogravure--

In gravure printing, the image areas are recessed relative to the nonimage areas. The gravure cylinder rotates in an ink trough or fountain. Excess ink is removed by a steel doctor blade. The paper is pressed against the cylinder as it turns, by use of a rubber-covered impression roll. When the process is roll-fed it is known as rotogravure. Sheet-fed gravure is not widely used.

Rotogravure requires very fluid inks, with solvent contents ranging from 55 to 75 percent and higher. Typical solvents include alcohols, aliphatic naphthas, aromatic hydrocarbons, esters, glycol ethers, ketones, nitroparaffins, and water. Solvent is evaporated in low-temperature dryers [(23° to 120°C), (70° to 250°F)], usually indirectly heated by steam or hot air. Steam drum dryers can be used.

3.13.1.2 Flexography--

In flexographic printing, as in letterpress, the image areas are raised above the nonimage surface. The distinguishing feature is that the image carrier is made of rubber and other elastomeric materials. Flexographic presses are usually rotary web presses, i.e., roll-fed. The flexographic printing market includes flexible packaging and laminates, multiwall bags, milk cartons, folding cartons, corrugated paper, paper cups and plates, labels, tags, tapes, envelopes, and gift wrap.

Flexography uses very fluid inks with organic solvent content ranging from 50 to 85 percent. The inks dry by solvent evaporation, usually in high-velocity air dryers at air temperatures below 120°C (250°F). Solvents that do not damage rubber must be used. Typical solvents are alcohols, aliphatic hydrocarbons, glycols, esters, glycol ethers, glycol ether esters, and water.

3.13.2 Emissions

The major air pollutants from printing operations are those from evaporation of organic solvents used in ink dilution and cleanup. Minor quantities of dust (from workroom activity) and diffuse fumes (from dryers) may be also vented to the atmosphere.

The primary sources of organic emissions are from the drying of inks. Types and quantities of emissions depend mainly on the inks and solvents used, the type and size of printing process, the requirements of the job being printed (ink consumption), and the degree of emission reduction achieved by control devices.

Printing inks are composed of materials similar to those used in surface coatings: pigments, vehicles, and solvents. The specifications for an ink vary widely according to the application[3] and influence the quantity and composition of the VOC emissions.

The following materials used as solvents in printing inks,[3] usually in combinations, determine the composition of the VOC emissions:

- toluene
- xylene
- heptane
- hexane
- isooctane
- mineral spirits
- Stoddard solvent
- naphthas
- heavy naphthas
- methyl ethyl ketone
- methyl isobutyl ketone
- ethyl acetate
- methanol
- ethanol
- propanol
- isopropanol
- butanol
- ethylene glycol
- glycol ether esters
- glycol esters
- acetone
- ethyl acetate
- isopropyl acetate
- normal propyl acetate

Inks incorporating these solvents are considered conventional inks. Ultraviolet and electron-beam-curable inks, waterborne inks, and heat-reactive inks are discussed under control measures. In gravure and flexography more solvent is added directly to the ink troughs, and emissions are not directly related to the ink composition.

3.13.3 Control Measures

Emissions can be reduced by add-on control devices and by the use of low-solvent inks as summarized in Table 3.13-2. The applicability of each control method to each printing technique is discussed below.

3.13.3.1 Add-On Control Equipment--

Fume incinerators (direct flame and catalytic) and carbon adsorbers are the only devices with proven high efficiency in controlling hydrocarbon vapors from rotogravure and flexographic printing operations.

Incineration--Incineration is a technically feasible method of controlling emissions from all printing operations. Both direct-flame and catalytic incinerators are potential methods of controlling emissions from flexography and package gravure printing. In a direct-flame incinerator a temperature of 600° to 680°C (1100° to 1250°F) and a residence time of 0.3 to 0.5 second are generally sufficient to achieve 90 percent oxidation of most organic vapors passing through the device. Temperatures of 760° to 820°C (1400° to 1500°F) may be necessary to oxidize aromatics such as toluene and xylene.

Heat recovery can substantially reduce the cost of incineration. Heat recovery equipment that uses the hot incinerator gases to preheat dryer exhaust gases prior to incineration reduces incinerator fuel requirements. In some cases heat equipment can be used to supply the heated air required at the dryer.[4]

A third type of incinerator, the pebble-bed, has been suggested as an applicable control for graphic arts processes. Pebble-bed incinerators combine the functions of a heat exchanger and a combustion device, as shown in Figure 3.13-1. The solvent-laden exhaust from the dryers and floor sweeps enters one of the pebble beds, which has been heated by combustion chamber exhaust. Oxidation of the vapors starts in the preheated bed and is completed in the combustion chamber. The exhaust gases exit through a second pebble bed, transferring heat to the pebbles. Pebble-bed systems are designed to achieve a heat recovery efficiency

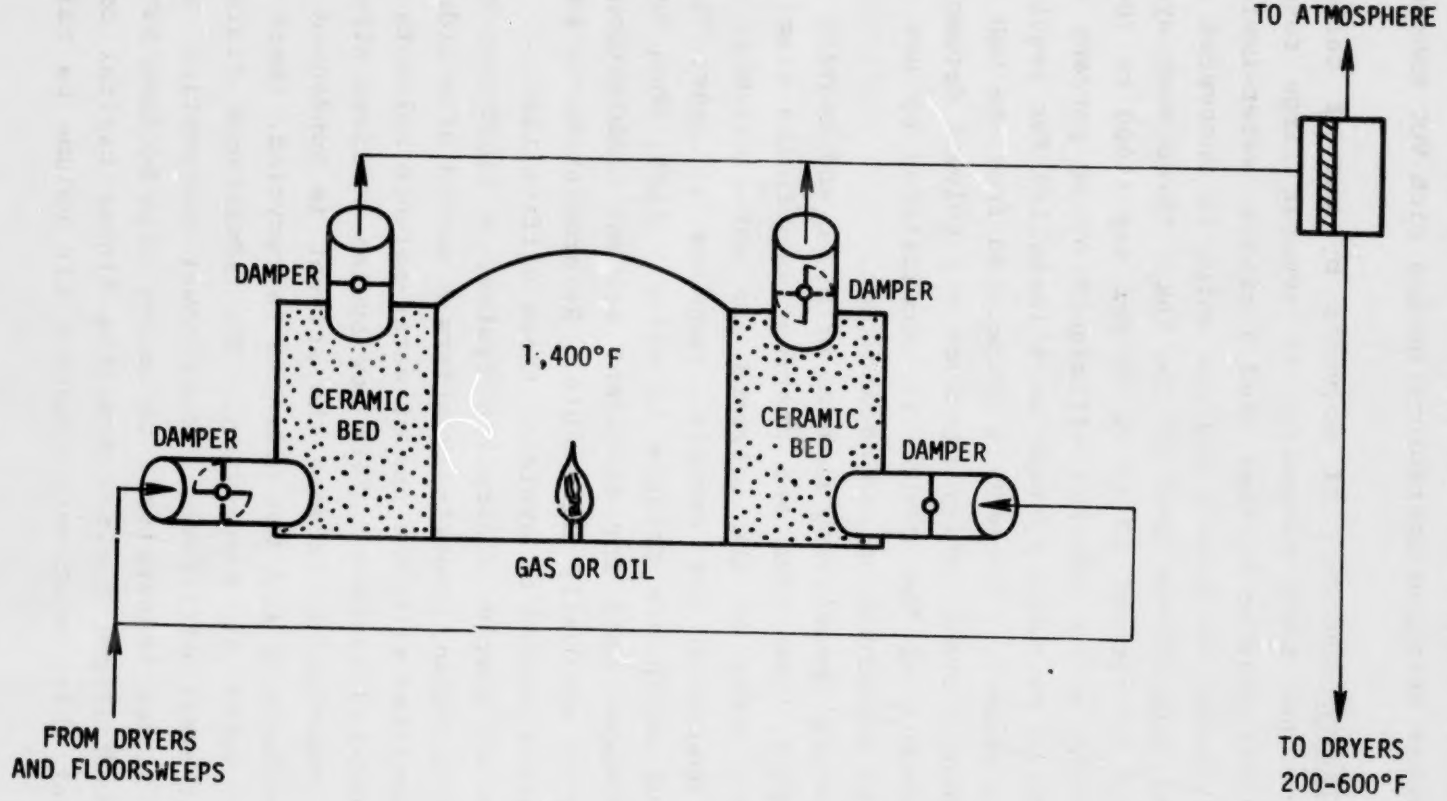
TO ATMOSPHERE
DAMPER
DAMPER
1,400°F
CERAMIC BED
CERAMIC BED
DAMPER
DAMPER
GAS OR OIL
FROM DRYERS AND FLOORSWEEPS
TO DRYERS 200-600°F

Figure 3.13-1. Ceramic-bed regenerative-type incineration and heat recovery system.[8]

of 85 percent. Use of pebble-bed incinerators appears to be best suited to continuous printing operations having rich VOC exhaust streams.

Carbon adsorption--Recovery of solvents by use of carbon adsorption systems has been successful at several large rotogravure plants. Rotogravure presses used a single, water-immiscible solvent (toluene) or else a mixture which is recovered in approximately the proportions used in the ink. Three such systems are reported to recover 23 to 26 kl per day (6000 to 7000 gal/day) of solvent at an average efficiency of 90 percent or greater.[5,6,7] These recovery systems were installed for regulatory and economic reasons. Solvent is evaporated from the web in indirect steam-heated ovens, which preclude any solvent decomposition. Regeneration of the carbon is accomplished by use of steam, followed by condensation and decantation.

Some rotogravure operations, such as printing and coating of packaging materials, use inks and coatings containing complex solvent mixtures. Many of the solvents are water-soluble. A folding carton operation for example, requires at least five solvents, some of which are soluble in water. Also, when frequent product changes call for different solvent combinations, solvent recovery is virtually impossible. Reformulation of inks may offer a possible method of avoiding these difficulties.

A new type of carbon adsorption system, a fluidized bed system developed in Japan, reportedly offers a method of avoiding the problems associated with the use of water-soluble solvents in conventional fixed-bed systems. This new system utilizes nitrogen gas as the desorbent. Because the solvent is condensed in indirect heat exchangers and the nitrogen is recycled, there is no mixing with water at desorption. The advantages claimed include better thermal efficiency, lower power consumption, and regeneration at higher temperatures to remove high boiling materials. The disadvantages include possible higher capital cost and a requirement that relatively constant air volume be maintained.[3]

Where add-on devices are used, the overall VOC reduction (control) efficiency is dependent upon the extent to which the capture system collects, contains, and delivers the VOC vapors to the control device inlet. Capture system efficiencies vary with the complexity and configuration of the printing operation and with the difficulty encountered in accessing emission points. The efficiency of capture systems at existing plants are reported to be 75 to 85 percent for publication rotogravure, 75 percent for packaging rotogravure, and 70 percent for flexography. Such capture systems, coupled with the 90 percent or greater VOC reduction achievable with incineration or carbon adsorption systems, provide an overall VOC reduction of 75 percent for publication rotogravure, 65 percent for packaging rotogravure, and 60 percent for flexography.

3.13.3.2 Use of Low-Solvent Inks--

Low-solvent inks are of three types: waterborne, high-solids, and radiation curable. Only waterborne inks are now widely used for packaging gravure and flexographic printing. Waterborne inks are not completely solvent-free because the volatile portion contains up to 35 percent water-soluble organic compounds. Although waterborne inks are used extensively in printing corrugated paperboard for containers, multiwall bags, and other packaging materials made of paper and paper products, their use is somewhat limited because they absorb into thin paper stocks and seriously weaken the paper.

Flexographic and rotogravure packaging printing operations with less demanding quality requirements can use waterborne inks to achieve emission levels comparable to those attained by the application of add-on control devices. A waterborne ink consisting of 75 volume percent water and 25 volume percent organic solvent in the solvent portion of the ink is considered to be equivalent in control effectiveness to either carbon adsorption or incineration.[9]

3.13.4 Emission Limits

Review of existing State Implementation Plans (SIP) showed no VOC emission limitations specific to the graphic arts industry. Rather, states have adopted general hydrocarbon emission regulations patterned after the Los Angeles Rule 66,[10] which has been modified pursuant to an EPA ruling that regards all hydrocarbons as photochemically reactive.

The South Coast Air Quality Management District Rule 442 (formerly Los Angeles Rule 66) places limitations on emissions from equipment using organic solvents or organic materials containing organic solvents. For organic materials that come into flame contact or are baked, heat-cured, or heat-polymerized, the limitation is 1.4 kg (3.1 lb) per hour, not to exceed 6.5 kg (14.3 lb) per day. For organic materials emitted from the use of photochemically reactive solvents, the limitation is 3.6 kg (7.9 lb) per hour, not to exceed 18 kg (39.6 lb) per day if not in flame contact, baked, heat-cured, or heat-polymerized. The above mass emission rate limitations do not apply if the emissions are reduced by at least 85 percent.

At this time no NSPS have been promulgated for the graphic arts industry. It is anticipated that such standards will be proposed for publication rotogravure in late 1979, after the completion of emission surveys and control technology studies.

3.13.5 Determination of LAER

The recommended limitations are based on SIP's and on performance information available in early 1979. It is anticipated that several additional SIP regulations covering these sources will be promulgated and/or modified in 1979 and 1980 and that appreciable new performance data will become available in the near term. Conceivably, some SIP regulations may be more stringent than the LAER suggested herein. Furthermore, performance testing may show that more stringent limits than those suggested are feasible or it may show that the suggested limits are appropriate or that they are not achievable for some specific subcategories. In any case, the basis for determining LAER for many source categories is expected to change frequently. Since LAER is near the vanguard of control technology, a more detailed analysis is particularly necessary when addressing modified or reconstructed facilities subject to the provisions of Section 173 of the Clean Air Act. Emission limitations reasonable for new sources may in some instances be economically or technically unreasonable when applied to modified or reconstructed sources of the same type.

The most stringent regulations in State Implementation Plans are patterned after Los Angeles Rule 66. Emission reductions achieved in practice exceed those required by the most stringent SIP regulations. Incineration, carbon adsorption, and the use of low-solvent-content inks are proven techniques for reducing VOC emissions from rotogravure and flexographic printing.

The use of incineration may be constrained where natural gas is in short supply. Incorporating heat recovery to the extent possible will reduce the total fuel requirements. Generally, incineration is technically feasible when carbon adsorption with solvent recovery is not possible. The use of carbon adsorption may increase energy requirements, but it also may enable recycling of solvents. Waterborne ink can generally be used for packaging and specialty rorogravure and flexographic printing operations with relatively sturdy substrate. The feasibility of ink substitution must be determined on a case-by-case basis, depending on product specifications and the type of process used. Low-solvent inks may be developed and used to yield reductions equal or close to those achieved with control system hardware.

In actual operation, direct-flame and catalytic incinerators have demonstrated emission reductions of 90 to 95+ percent on certain types of printing operations. Carbon adsorption units can reduce emissions by 90 percent or more on rotogravure processes using solvents that are insoluble in water. These values pertain to the efficiency of the device only.

This guideline relies substantially on information provided in the EPA Control Techniques Guideline (CTG), Volume VIII: Graphic Arts--Rotogravure and Flexography (Reference 2). The overall emission reductions reported as achievable in the CTG pertain to retrofit application of control strategies. Since LAER applies only to new (modified) facilities, greater emission reduction can be expected. Unlike retrofit systems, new installations offer an opportunity to maximize plant layout, process methods, and capture-control system designs to obtain the most effective VOC control. Considering these factors, it appears the following overall reductions of VOC emissions from solvent-borne inks are attainable with effective capture-control systems and are presented as suggested LAER values: publication rotogravure, 80 percent; packaging rotogravure, 70 percent; and flexography, 65 percent.

Comparable emission reductions achieved by use of water-borne and/or low-solvent (high-solids) inks rather than solvent-borne inks are considered as meeting the LAER values.

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3.14 MAJOR SOURCE CATEGORY: AUTOMOBILE AND LIGHT TRUCK COATING--VOLATILE ORGANIC COMPOUND (VOC) EMISSIONS

3.14.1 Process Description

Automobile and light truck coating is a multistep operation carried out on a conveyor system where each vehicle body receives several coats of paint to enhance appearance and protect against adverse weathering.[1] In some coating operations, hoods and fenders are coated separately from the main body line and joined to the body after coating.

Although no automobile or light truck assembly line is "typical," features common to all are shown in Figure 3.14-1. As the process begins, an automobile body emerges from the body shop and undergoes a solvent wipe and metal treatment step (usually a phosphate wash cycle) to improve paint adhesion and corrosion resistance. The first coat, a primer, is applied by dip or spray methods; then the unit is baked. A second prime coat (surfacer or guide coat) is sometimes applied by spraying. After the prime coats have been baked, the topcoat is applied by a combination of manual and automatic spray devices in a spray booth. The topcoat is applied in one to three steps with a bake (cure) step after each. Additional coats of different colors may also be applied. The coated body then goes to the trim shop, where the interior and exterior trim is applied.

Touchup coating is applied at various stages of the top-coating line and the touchup sprays are cured in the line oven. After the final touchup, the coating must be cured in a low-temperature oven to protect heat-sensitive plastics and rubber parts built into the vehicle. Organic-solvent-borne coatings have been used in conjunction with the low-temperature curing.

3.14.2 Emission of Pollutants

Emissions of volatile organic compounds (VOC) occur at three significant facilities in a vehicle finishing operation: 1) the

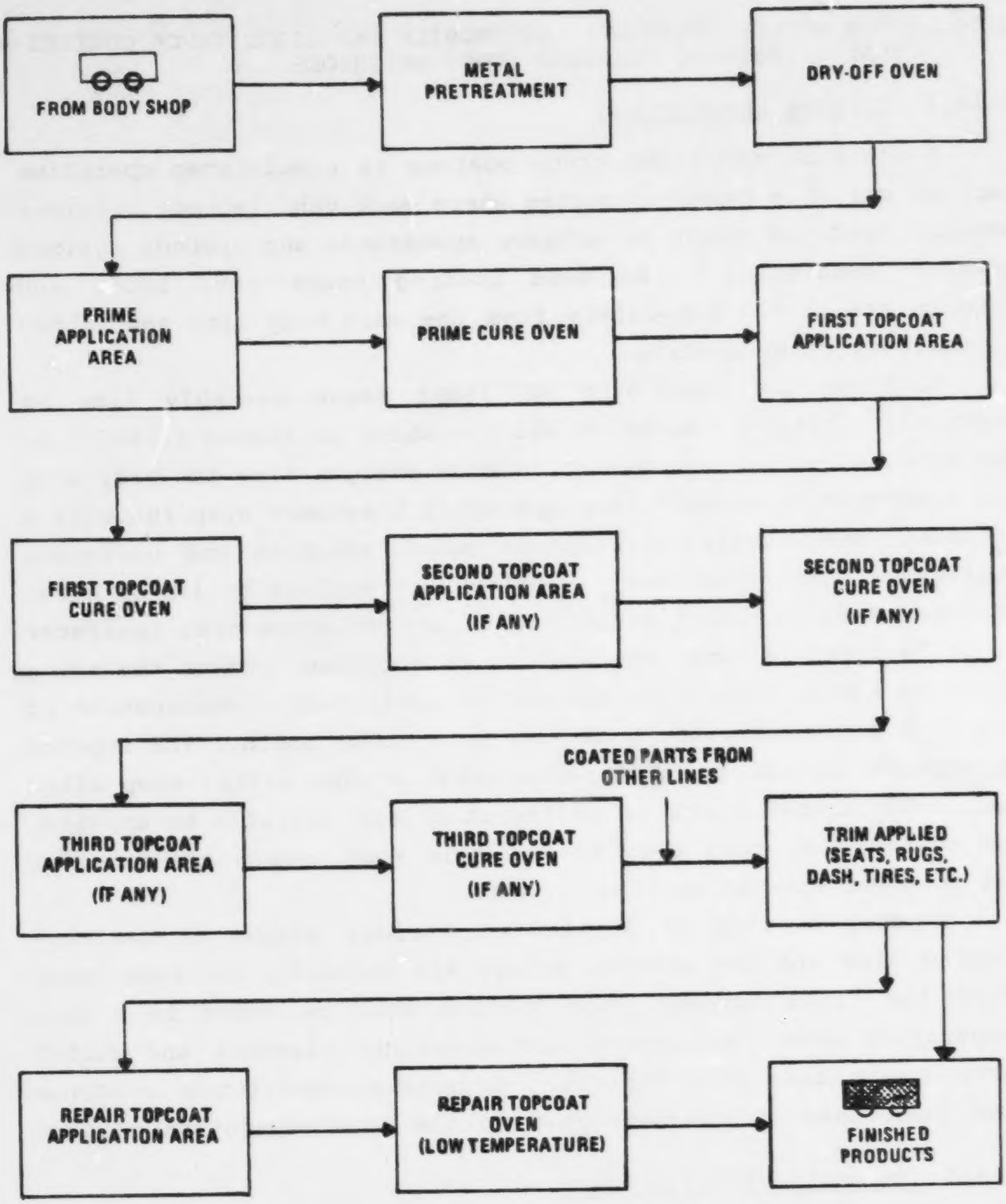
FROM BODY SHOP
METAL PRETREATMENT
DRY-OFF OVEN
PRIME APPLICATION AREA
PRIME CURE OVEN
FIRST TOPCOAT APPLICATION AREA
FIRST TOPCOAT CURE OVEN
SECOND TOPCOAT APPLICATION AREA (IF ANY)
SECOND TOPCOAT CURE OVEN (IF ANY)
COATED PARTS FROM OTHER LINES
THIRD TOPCOAT APPLICATION AREA (IF ANY)
THIRD TOPCOAT CURE OVEN (IF ANY)
TRIM APPLIED (SEATS, RUGS, DASH, TIRES, ETC.)
REPAIR TOPCOAT APPLICATION AREA
REPAIR TOPCOAT OVEN (LOW TEMPERATURE)
FINISHED PRODUCTS

Figure 3.14-1. General flow diagram for automotive and light truck assembly plants. Main bodies may be on separate lines from hoods and fenders.

prime coating line, 2) the topcoating line, and 3) the final repair area. In each of these facilities, emissions occur in the application area, the flash-off area, and the cure oven.

The prime coat serves the dual function of protecting the surface from corrosion and providing for good adhesion of the topcoat. Organic-solvent-borne primer is usually applied by a combination of manual and automatic spray methods, with or without the use of electrostatic techniques. When manual methods are used, health regulations require that solvent concentrations be kept low. Waterborne primers may be applied by spray or dip methods. When organic-solvent-borne spray is used, 85 to 90 percent of the solvent evaporates in the booth and flash-off area; the remaining 10 to 15 percent evaporates in the oven. Typical solvent emissions from the prime coating operation are 193 kg/h (425 lb/h) with a spray applied two-coat prime containing 32 percent solids enamel, and 18 kg/h (40 lb/h) with EDP coating. The EDP is followed by a prime surfacer coat that has typical solvent emissions ranging from (120 to 300 lb/h) depending on the type of coating used.

The topcoat is applied in one to three steps, each followed by a curing oven. The topcoat colors used on-line vary in accordance with consumer requests. Metallic and "tutone" finishes are also applied on the topcoat line. The coating is applied by manual and/or automatic spraying in an enclosed spray booth. Solvent concentrations in the manual booth must comply with health regulations. Because of the length of time that the auto body is in the spray booth, 85 to 90 percent of the solvent evaporates in the booth and its flash-off area. Typical solvent emissions from the topcoat line are 386 kg/h (850 lb/h) with a 32 percent solids enamel, 1.3 Mg/h (3000 lb/h) with a 12 percent solids lacquer, and 77 kg/h (170 lb/h) with waterborne coatings.

Areas damaged during trim application or imperfections not detected in the main paint shop are repainted in a final repair step. Because the vehicle now contains heat-sensitive materials, coatings used for repair are generally limited to solvent-borne materials that can be dried in low-temperature ovens. Production in the repair area is intermittent. Typical emissions from the final repair area are 13.3 kg/h (29.3 lb/h) with solvent-borne coatings.

Uncontrolled organic emissions from coating of vehicles with organic-solvent-borne coatings can range from less than 272 kg/h (600 lb/h) to more than 1.8 Mg/h (4000 lb/h) over an entire assembly line. This wide range is caused by variations in the surface area coated on different vehicles, the number of vehicles coated per hour, the coating application method, and the solvent content of the coatings. A plant may operate more than one assembly line.

Sources of organic emissions from a vehicle assembly plant that are not considered here include the application of adhesives and soundproofing materials. These account for about 10 to 30 percent of total organic emissions from the plant. Other fugitive emissions occur during the initial solvent wipe, plant cleanup, and solvent storage.

3.14.3 Control Measures

3.14.3.1 Prime Coating Line--

The use of waterborne spray primers and/or electrocoating systems provides substantial reductions in VOC emissions and is the most common control measure now used in the industry. The greatest emission reduction occurs when primer is applied by electrophoretic (electrodeposited) dip of the total body. Only waterborne coatings can be applied by this process. Typical solvent contents of the coatings (not including water) range from 0.8 to 2.0 lb solvent/gal coating. The object to be coated is immersed in a waterborne coating and an electric potential difference is induced between the object and the coating bath. As the object emerges from the bath, its coating is 90 percent solids (by volume), 9 percent water, and 1 percent organic cosolvent. Excess coating is returned to the bath by washing the object with makeup and ultra-filtered water. Because of the extremely low-solvent usage [about 3 kg/h (7 lb/h)], the exhaust from this oven requires no further emission control unless it presents an odor problem. The electrophoretic dip process is used at over 40 percent of U.S. assembly plants and is very widely used in Europe.[2,3,4]

The percentage reduction achieved by a change to electrophoretic coatings depends on the original system. For example, if the change is from a 32-percent solids primer [about 2.4 kg (5.3 lb) of organic solvent per gallon of coating] to electrophoresis [about 0.45 kg (1.0 lb) of organic solvent per gallon of coating], the reduction is 80 percent. Reduction in emissions of 95 percent by use of this priming method have been reported.[5]

The major limitations of electrophoretic dip coating are that it can be used only directly over metal or other conductive surfaces and only one coat can be applied. Electrical requirements increase by about 1400 kW with this method; this represents a 12 percent increase over the 12,000 kW required for applying organic-solvent-borne primers. Additionally, the electrophoretic dip coatings may contain amines that are driven off during the curing step; incineration of the oven exhaust is then required to eliminate the visible emissions and malodors associated with amines.

Spraying of waterborne primers is possible, but such operations are not readily automated. Some plants do spray waterborne primers, and this is a viable option for many plants, especially when more than one primer coat is required.

The use of organic-solvent-borne coatings with relatively high solids content inherently reduces VOC emissions because of the lower-solvent content. The achievable reduction depends on a comparison of the higher-solids coating with the coating that would otherwise be used. For example, a coating with 50 percent solids achieves an 86 percent reduction of emissions compared with a coating with a lacquer with 12 percent solids; the reduction is only 53 percent, however, with respect to use of an enamel with 32 percent solids. Obviously, even further reductions can be achieved if the transfer efficiency is improved or an add-on control device is also installed. Topcoats containing 37-40 volume percent solids and nearly 50 percent solids have been used by Volkswagon and American Motors, respectively.

Add-on control measures available for use on prime coating lines include activated carbon adsorption and incineration. Pilot studies on the use of carbon adsorption in primer spray booths and flash-off areas have indicated potential for reductions of greater than 85 percent.[6,7] Presently, no full-scale carbon adsoption systems are in operation on any automobile or truck coating line. Carbon adsorption is technically feasible, however, and General

Motors has acknowledged that activated carbon can be used effectively on spray booths and ovens to reduce solvent emissions by 90 to 95 percent if the system is properly engineered and regularly maintained.[6,7]

Both catalytic and thermal incinerators could be used to control VOC emissions from prime and topcoating spray booths and ovens. Incinerators operated at high temperatures can almost completely destroy organic vapors.[8] Reductions in VOC emissions of 90 to 98 percent have been reported with the use of thermal incinerators on primer and topcoat ovens.[1,5,9] The fuel consumption by incinerators of oven exhaust need not be excessive if the oven operates at a relatively high proportion of the lower explosive limit (LEL). Heat recovery systems become attractive with increased VOC concentration. With spray booth and flash-off area exhausts, however, the high flow rates and very low organic vapor concentrations require that an incinerator consumes huge amounts of fuel. Moreover, the opportunity for more than primary energy recovery is restricted by the limited need for the large amount of energy available. For these reasons, although technically feasible, incineration of spray booth and flash-off area exhaust is not practiced at any plant.

3.14.3.2 Topcoating Line--

Many of the control measures applicable to the prime coating line can also be used on the topcoating line. Reductions in organic solvent emissions of up to 92 percent from topcoat spray booths and ovens are possible by use of waterborne topcoats.[1] As before, the exact reduction depends on the original coating and the substitution. Waterborne coatings are currently being used at two General Motors automobile assembly plants in California on a full-scale basis. These plants have reported 88 percent reductions in VOC emissions as a result of the coating substitution.[5] As with waterborne primer systems, however, use of waterborne topcoats increases electrical usage (in this case, by 42 percent). Difficulties in precipitation and dewatering of the collected overspray increase the solid waste disposal problem. Waterborne coatings are sensitive to humidity, and it has been reported that suitable waterborne coatings do not exist for van interiors.

The use of higher-solids coatings, activated carbon adsorption, or thermal and catalytic incineration on the topcoat line can achieve the same reductions as presented for prime coatings and are subject to the same limitations described earlier.

Recently developed powder coatings may have possible application in the automobile and light-duty truck coating industry. To date, their use in this industry has been limited by the need to change colors often and the lack of availability in metallic colors. Preliminary studies indicate that powder coating systems reduce energy requirements, have acceptable durability, offer 95 to 99 percent utilization, and essentially eliminate all organic solvent emissions.[5,10] Within the last year, the major auto producers have resumed investigation of powder coatings.

3.14.3.3 Final Repair--

Control of emissions from the final repair spray booth and oven has not been practiced because the intermittent operations make add-on control equipment less cost-effective than in other areas. These emissions can be collected and sent to an activated carbon adsorption unit or incinerator at another location within the plant. This system, however, would not provide cost-effective control. Considerable reductions in emissions can be accomplished by the use of higher-solids repair coatings, but this measure has not been practiced at any plant.

3.14.4 Emission Limits

The initial criterion for defining lowest achievable emission rate (LAER) for a surface coating industry is the degree of emission control required by the most stringent regulation adopted and successfully enforced by a state or local air pollution control agency.

Most organic solvent emission regulations are patterned after what is now Rule 442 of the South Coast (California) Air Quality Management District.[11] Review of the regulations applicable in the 16 states that contain about 85 percent of all surface coating industries showed that these are essentially the same as Rule 442.[12] Indiana has the most stringent regulation, which limits organic solvent emissions to 1.4 kg/h (3 lb/h) or 6.8 kg/h (15 lb/day) unless such emissions are reduced by at least 85 percent, regardless of the reactivity or temperature of the solvent. Organic solvents that have been determined to be photochemically unreactive or that contain less than specified percentages of photochemically reactive organic materials are exempt from this regulation. Recent research, however, has indicated that substituting low-reactivity solvents for higher-reactivity solvents may improve photochemical oxidant air quality in one city while worsening it in downwind regions.[13] Accordingly, EPA has adopted a policy emphasizing the need for "positive reduction techniques" rather than substitution of compounds.[11] Thus, the "low reactivity" solvents will no longer be exempt.

California Air Resources Board has recently adopted a model rule for the control of VOC emissions from light- and medium-duty vehicle assembly plants. This rule limits VOC emissions from the prime or topcoat lines to 0.275 kg/liter (2.29 lb/gal) of coating as applied, excluding water, unless the emissions are reduced by 90 percent through treatment of the exhaust.[5] Other recommended emission limitations represent rates achievable by application of reasonably available control technology (RACT). It has been proposed that these rates also be adopted as new source performance standards (NSPS) for the industry. The recommended VOC emission limitations achievable by application of RACT are: 1) 0.23 kg/liter (1.9 lb/gal) of coating minus water for the prime coating line, 2) 0.34 kg/liter (2.8 lb/gal) for the topcoating line, and 3) 0.58 kg/liter (4.8 lb/gal) for the final repair area. The recommended limitation for prime coating is based on the use of water-borne electrophoretic dip primer, 0.15 kg/liter (1.2 lb/gal) of coating minus water, followed by water-borne primer surfacer with 0.34 kg/ liter (2.8 lb/gal) of coating minus water.

3.14.5 Determination of LAER

The recommended limitations are based on SIP's and on performance information available in early 1979. It is anticipated that several additional SIP regulations covering these sources will be promulgated and/or modified in 1979 and 1980 and that appreciable new performance data will become available in the near term. Conceivably, some SIP regulations may be more stringent than the LAER suggested herein. Furthermore, performance testing may show that more stringent limits than those suggested are feasible or it may show that the suggested limits are appropriate or that they are not achievable for some specific subcategories. In any case, the basis for determining LAER for many source categories is expected to change frequently. Since LAER is near the vanguard of control technology, a more detailed analysis is particularly necessary when addressing modified or reconstructed facilities subject to the provisions of Section 173 of the Clean Air Act. Emission limitations reasonable for new sources may in some instances be economically or technically unreasonable when applied to modified or reconstructed sources of the same type.

LAER for automobile and light-duty truck coating is determined to be a combination of limitations represented by RACT and the emission reductions achieved-in-practice using current technology and control measures. For prime coat application, the use of waterborne coatings in the electrophoretic dip process followed by water-borne primer surfacer represents LAER. This reduction is comparable to the RACT limitation of 230 g of solvent/liter (1.9 lb/gal) of coating minus water and can also be achieved using higher solids coatings in conjunction with an oven incinerator.

For the topcoating line, LAER can be met by the use of waterborne coatings with achievable reductions of 88 to 92 percent, which is again comparable to the RACT limitation of 320 g of solvent/liter (2.8 lb/gal) of coating minus water. Similar reductions are achievable when using other low-solvent coatings such as powders or higher solids coatings, although oven exhaust incineration is required when higher solids coatings are used to achieve the 88 to 92 percent reduction.

For the final repair area, higher solids coatings would represent LAER if this technology had been demonstrated in the industry. LAER is considered to be the recommended VOC limitation capable of being met by the application of RACT, i.e., 580 g of solvent/liter (4.8 lb/gal) of coating minus water.

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3. Report of trip by J.A. McCarthy, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina to General Motors assembly plants in South Gate and Van Nuys, California. November 17, 1975.

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3.15 MAJOR SOURCE CATEGORY: METAL FURNITURE AND LARGE APPLIANCE COATING - VOLATILE ORGANIC COMPOUND (VOC) EMISSIONS

3.15.1 Process Description

Metal furniture is manufactured for both indoor and outdoor use by two general consumer categories: business/institutional and residential. Metal furniture products include tables, chairs, wastebaskets, beds, desks, lockers, benches, shelving, file cabinets, lamps, room dividers, and many other similar items. Size of the plants varies with the type of furniture manufactured, the number of manufacturing and coating lines, and the amount of assembly required.

Large appliance products include doors, cases, lids, panels and interior support parts of residential and commercial washers, dryers, ranges, refrigerators, freezers, water heaters, dishwashers, trash compactors, air conditioners and similar products. A typical large appliance plant is much bigger than a typical metal furniture plant, but may manufacture only one or two different types of appliances and contain as few as two coating lines. Most of the coatings used in these industries are enamels, although quick-drying lacquers are sometimes applied to repair scratches and nicks that occur during assembly. Some coatings are metallic. The coatings applied to metal furniture and large appliances must protect the metal from the corrosive action of agents such as heat, water, detergents, and the outdoor elements. They must have good adhesion properties to prevent peeling or chipping, must be durable, and must meet customer standards of appearance. Coatings may contain mixtures of 2 to 15 different solvents. Prime and interior single coat materials are typically 25 to 36 percent solids by volume, and topcoat and exterior single coats are 30 to 40 percent solids. The underside of many exterior large appliance parts are sprayed with gilsonite to provide additional moisture resistance and sound-deadening properties. The gilsonite is typically sprayed at about 25 to 30 percent solids by volume.

A typical metal furniture line is depicted in Figure 3.15-1; a typical large appliance line is shown in Figure 3.15-2. Unassembled, partly assembled, or

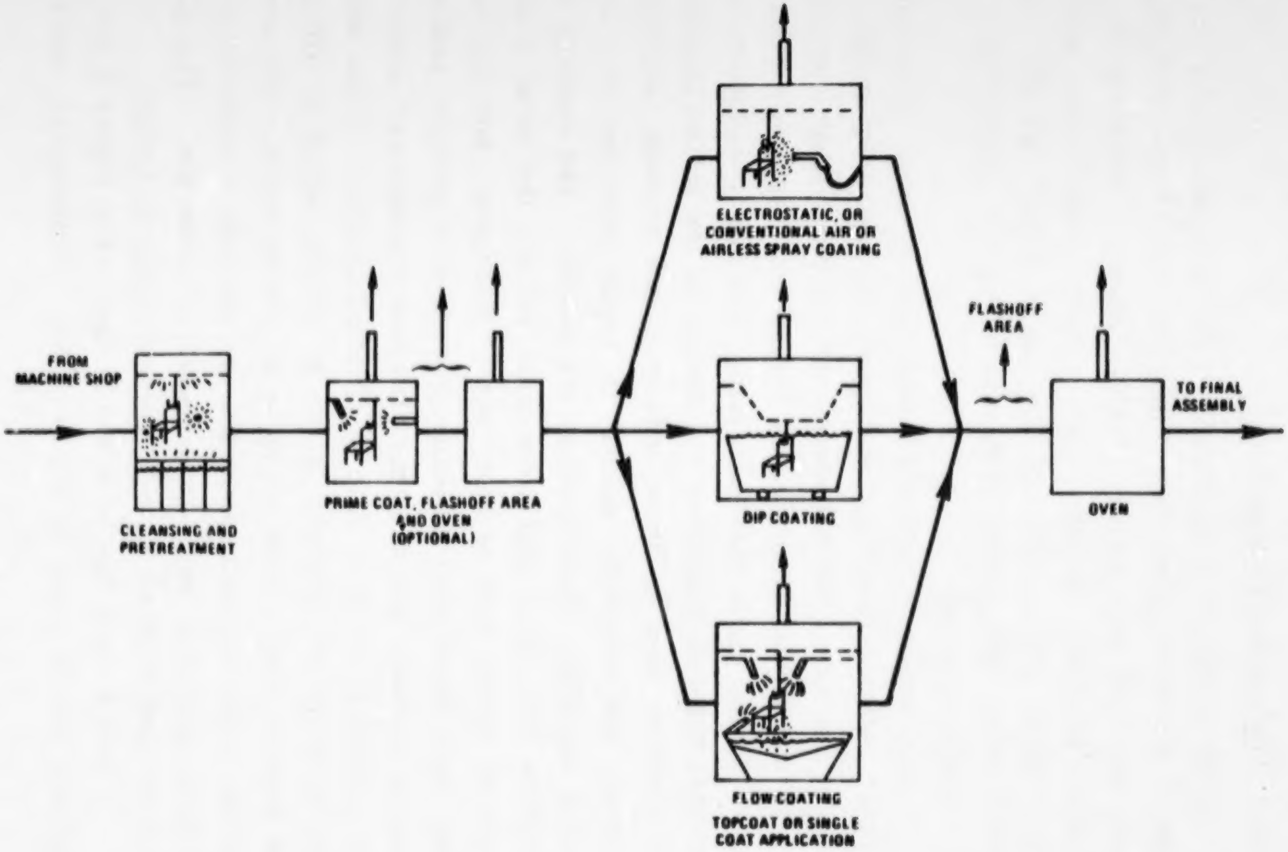
FROM MACHINE SHOP
CLEANSING AND PRETREATMENT
PRIME COAT, FLASHOFF AREA AND OVEN (OPTIONAL)
ELECTROSTATIC, OR CONVENTIONAL AIR OR AIRLESS SPRAY COATING
DIP COATING
FLOW COATING
TOPCOAT OR SINGLE COAT APPLICATION
FLASHOFF AREA
OVEN
TO FINAL ASSEMBLY

Figure 3.15-1. Coating of metal furniture.

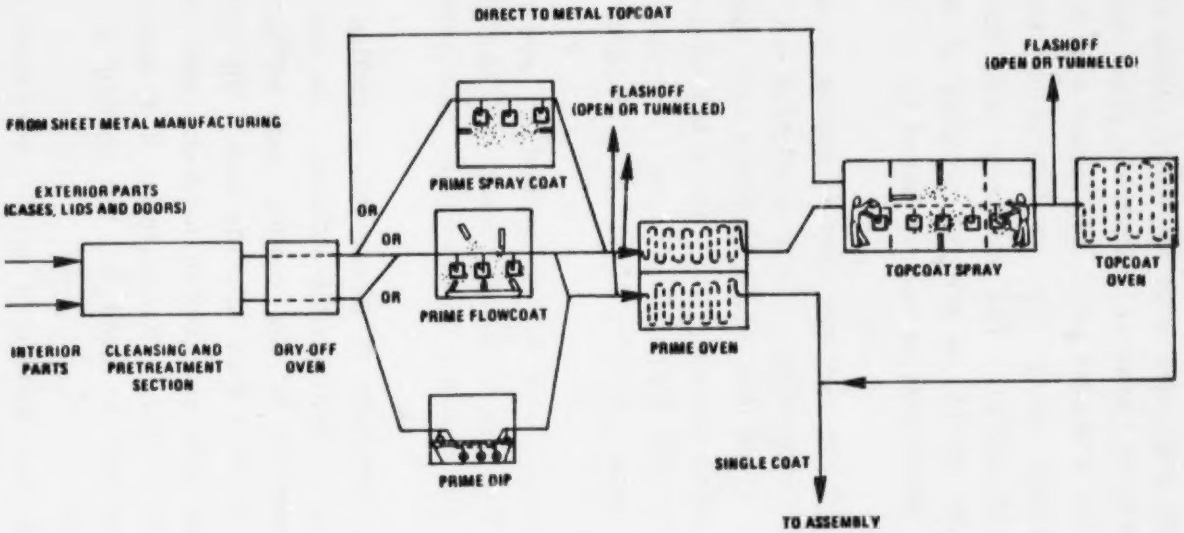
DIRECT TO METAL TOPCOAT
FROM SHEET METAL MANUFACTURING
EXTERIOR PARTS (CASES, LIDS AND DOORS)
INTERIOR PARTS
CLEANSING AND PRETREATMENT SECTION
DRY-OFF OVEN
OR
OR
OR
PRIME SPRAY COAT
PRIME FLOWCOAT
PRIME DIP
FLASHOFF (OPEN OR TUNNELED)
PRIME OVEN
SINGLE COAT
TO ASSEMBLY
TOPCOAT SPRAY
FLASHOFF (OPEN OR TUNNELED)
TOPCOAT OVEN

Figure 3.15-2. Coating of large appliances.

totally assembled furniture or appliance pieces are first transported on a conveyor through an alkaline cleansing and pretreatment process. Sometimes the wash section is omitted and the pieces are cleaned in a shot-blasting chamber or organic solvent cleaning operation.

Most metal furniture and some large appliance pieces are finished with a single coat. Other surfaces, however, require a prime coat because of the topcoat formulation or the intended use. The prime coat may be applied by electrostatic or conventional spray, dip, or flowcoating techniques (coating techniques are discussed below). The substrate with the prime coat then goes through a flash-off period to prevent popping of the film when the coating is baked. The prime coat is usually baked in an oven at about 160° to 200°C (300° to 400°F).

The topcoat or single exterior coat may be applied to metal furniture by spraying, dipping, and flowcoating. Large appliances are usually sprayed. A touch-up operation or application of highlighting tone follows. The coated part passes through a flash-off zone and into a baking oven. The baking oven usually contains several temperature zones ranging from 160° to 230° (300° to 400°F). Some metal furniture parts are air dried, but all appliance parts are heat cured.

The heart of a coating line is the method by which the coating is applied. Regardless of the type of coating, there are basically three possible modes of application: dip coating, flow coating, and spraying. Each are briefly described below.

Dip coating is the immersion of pieces into a coating bath. The tank that contains the coating is continuously agitated. As the parts move on a conveyor, they are immersed in the coating and withdrawn; the excess coating is then allowed to drain back into the tank. Dip coating, in addition to being one of the most efficient coating methods, also provides the best coverage of cavities and crevices. Consequently, it is used largely for prime or undercoating but may also be used for top coating in cases where the plant uses one or two colors.

Flow coating is also used when only one or two colors are applied. As the parts are moved by a conveyor through an enclosed booth, stationary or oscillating nozzles at various angles emit streams of coating, which flow over the part. Excess coating, which drains into a sink on the bottom of the booth, is filtered and recycled.

Spraying is the most used of all coating application techniques. There are three natural categories of spray coating based upon the way the coating is atomized and transported from the delivery device to the metal surface. Air spray utilizes a high velocity air gun to atomize the coating into fine droplets and carry the droplets to the substrate. Airless spray is accomplished by forcing a liquid coating through a small orifice at very high pressures. In electrostatic spraying, the coating is atomized by one of the above methods or by feeding the coating to a disk or bell rotating at high rpm. The paint particles are given a negative charge by the atomization device and are attracted to the grounded metal parts. Any of the spraying methods can be used manually or with automatic controls. Most spray coating in metal furniture facilities is done manually, whereas in large appliance facilities it is done automatically. The important difference among spray coating methods is transfer or application efficiency. Conventional air or airless sprays are typically 30 to 50 percent efficient. Electrostatic spray guns can be as high as 65 percent efficient and high speed disks and mini bells can achieve 90 percent efficiency.

Spray coating and, frequently, other coating methods are performed in a booth to contain any over-spray or drippings, to prevent dirt from contacting the paint, and to control the temperature and humidity at the point of application. Air flow rates through spray booths vary depending on whether they are occupied and on their size. OSHA prescribes minimum air velocities to assure capture of overspray and to keep VOC concentrations below the threshold limit values (TLV).

As has already been mentioned, the baking oven usually contains several zones at temperatures ranging from 160° to 230°C (300° to 450°F). The exhaust air flow rate depends on the size of oven openings through which parts enter and exit. Insurance underwriter requirements typically limit the atmosphere within industrial baking ovens to 25 percent of the lower explosive limit (LEL); however the use of continuous monitoring equipment changes the requirements and allows concentrations as high as 40 percent of the LEL.

3.15.2 Emission of Pollutants

The significant emitting facilities in a metal furniture or large appliance coating plant are the prime and topcoating lines. On each line, VOC's are emitted from the coating area, flash-off area, and oven.[1] As shown in Table 3.15.1, it is estimated that 65 to 80 percent of the uncontrolled VOC emissions are released from the spray booth and flash-off area in spray applications, and the remaining 20 to 35 percent from the oven. In a dip or flowcoat application, an estimated 50 to 60 percent of the VOC emissions come from the coating and flash-off area, and the other 40 to 50 percent from the oven. Typical uncontrolled VOC emissions from the coating of metal file cabinets are 6.8 kg/h (15 lb/h) from the entire plant. Typical uncontrolled emissions from the coating of automatic washers are 13.2 kg/h (29 lb/h) from the coating area and oven, and 11.8 kg/h (26 lb/h) from the sound-deadener application.

3.15.3 Control Measures

Operators of metal furniture and large appliance coating processes use several measures to reduce VOC emissions at the point of application or remove them from the exhaust stream. Waterborne coating is a feasible control measure. Waterborne coating can be applied by spray, dip, flowcoat, or electrodeposition (EDP). Electrodeposition is limited to waterborne coatings used for the primer or single coat application. EDP coatings are applied from an aqueous bath, which contains about 10 to 15 percent solids (by volume) and 2 to 4 percent organic solvents. Applying direct current in the bath causes the solids to become attached to the grounded metal piece. Electrodeposition can be performed either anodically or cathodically. The metal parts emerge from the bath with a coating containing about 90 percent solids (by volume), 1 to 2 percent organic solvent, and the balance water. Two automobile finishing plants using this application method report reductions in VOC emissions of 95 percent.[2] Large appliance plants using EDP have demonstrated 93 percent solvent reduction.* A more complete description of this process is presented in Section 3.14.3.

Emission reductions of 60 to 90 percent may be obtained by use of waterborne coatings on topcoat lines and primer or single coat lines where the

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*Data on metal furniture and large appliance operations supplied by paint company. April 14, 1978.

TABLE 3.15-1. DISTRIBUTION OF VOC EMISSIONS FROM METAL FURNITURE AND LARGE APPLIANCE COATING LINES[a]

(percent)

Application method	Application and flash-off area	Oven
Electrostatic spray	65	35
Conventional air or airless spray	80	20
Dip	50	50
Flow	60	40

Source: Reference 1, Volume III.

[a] The base case coating is applied at 25 volume percent solids and 75 volume percent organic solvent, which is equivalent to a VOC emission factor of 0.66 kg of organic solvent per liter of coating (5.5 lb/gal) minus water.

coating is applied by spray, dip, or flowcoat. Use of these coatings has produced an 87 percent reduction at some large appliance plants.* Temperature, humidity, gun-to-metal distance, and flash-off time affect the appearance and other characteristics of the coating.

Activated carbon adsorption, although technically feasible, has not been used in the metal furniture or large appliance coating industries. Carbon adsorption is a feasible control option for the application and flash-off areas because exhaust gases are at ambient temperatures and contain only small amounts of particulate matter that could foul the carbon bed. (Some particulate removal would be necessary at spray booths). Carbon adsorption could reduce emissions from these areas by 70 to 90 percent of the vapors that are drawn into the bed.[1] Use of activated carbon adsorption on paper and fabric coating lines has provided up to 98 percent removal of VOC vapors drawn into the bed.† For metal furniture or large appliance coating lines the mixture of solvents that are recovered cannot be used without further treatment. Collected mixed solvents can be used as fuel for ovens or other heating processes.

No serious technical problems are associated with the use of either catalytic or thermal incinerators at these facilities. Documentation of achievable reductions of 96 to 99 percent across the control device for incinerators used at automobile, can, coil, and paper coating facilities is presented in Sections 3.14, 3.16, 3.17, and 3.18, respectively. As discussed in Section 3.14.3, incineration of exhausts from the spray booth and flash-off areas requires auxiliary fuel. Fuel input can be reduced with heat recovery equipment.

Emissions from topcoat and single coat application and curing can be controlled by use of powder coatings. These may be applied electrostatically by spraying or dipping, or by dipping the preheated metal into a fluidized bed. Electrostatic spraying is more widely used than dipping because it can apply thinner films of coating. Powder spray coating requires a booth, as does spray coating with conventional coatings. Ventilation requirements are greatly reduced because the booths are not occupied. Electrostatic dipping is limited to simple shapes. The fluidized bed dipping method applies the powder only in thick films. Use of powder coating reduces energy requirements in the application area and greatly reduces VOC emissions. These coatings have acceptable durability and offer more than 95 percent utilization.[3] Reduction in VOC emissions may range from 95 to 99+ percent over conventional systems. Data reveal that the average solvent reduction for powder coating by electrostatic spray methods is 99 percent.* Several limitations are associated with the use of powder coatings in the metal furniture coating industry. Color changes require about half an hour of downtime to evacuate the spray booth and purge the former color from the application device. Color matching during manufacture of the powder is difficult; metallic coatings are not presently available; powder films have appearance limitations; they do not coat well within small recesses; and excessive humidity during storage or application can affect performance.

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*Data on metal furniture and large appliance operations supplied by paint company. April 14, 1978.

†Letter from W. C. Moses, Technical Manager, Chemical Plant Division, Suttcliffe, Speakman & Company, Limited. March 10, 1978.

Reductions of VOC emissions by choosing higher-solids coatings over conventional organic-solvent-borne coatings may range from 50 to 82 percent, depending on the solids content of the coating that would otherwise be used.[1] The average achievable reduction is 78 percent.* Higher-solids coatings are applied most effectively by automated electrostatic spraying, but manual and conventional spraying techniques can also be used. Some minimal increase in energy may be required to raise the pressure of the spray gun or heat the more viscous coating so that it can be pumped and atomized. Emissions from gilsonite application in the large appliance industry can also be controlled through use of higher-solids coatings; no data are available on the solvent reductions that can be obtained.

3.15.4 Emission Limits

The initial criterion for defining LAER for a surface coating industry is the degree of emission control required by the most stringent regulation adopted and successfully enforced by a state or local air pollution control agency.

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*Data supplied by paint company. April 14, 1978.

Most organic solvent emission regulations are patterned after what is now Rule 442 of the South Coast (California) Air Quality Management District.[4] Review of the regulations applicable in the 16 states that contain about 85 percent of all surface coating industries showed that they were essentially the same as Rule 442.[5] Indiana has the most stringent regulation in that it limits organic solvent emissions to 1.4 kg/h or 6.8 kg/h (3 lb/h or 15 lb/day) unless such emissions are reduced by at least 85 percent, regardless of the reactivity or temperature of the solvent. Organic solvents that have been determined to be photochemically unreactive or that contain less than specified percentages of photochemically reactive organic materials are exempt from this regulation.

In defining LAER for surface coating emissions, it is not appropriate to exempt solvents on the basis of their reactivity. Recent research has indicated that substituting low-reactivity solvents for higher-reactivity solvents may improve photochemical oxidant air quality in one city while worsening it in downwind regions.[6] Accordingly, EPA has adopted a policy emphasizing the need for "positive reduction techniques" rather than substitution of compounds.[4]

California Air Resources Board has recently adopted a model rule for the control of VOC emissions from metal parts and product coating operations.[7] This rule must be met within 3 years from the date of adoption. It limits the VOC emissions from baked coatings to 275 g solvent/liter (2.3 lb/gal) coating minus water, and from forced-air-dried coating to 340 g solvent/liter (2.8 lb/gal) of coating minus water.

A recent EPA publication presents emission limits achievable through the application of reasonably available control technology (RACT).[1] The recommended limitation for metal furniture coating is 0.36 kg of organic solvent/liter of coating minus water (3.0 lb/gal); for large appliance coating it is 0.34 kg/liter (2.8 lb/gal). These limitations are comparable to an 80 percent reduction in solvent emissions from each affected facility. There are currently existing facilities which meet or exceed the RACT limitations for both categories; therefore, it is concluded that LAER for metal furniture and large appliance coating is a function of controls achieved in practice rather than controls required by existing regulations.

3.15.5 Determination of LAER

The recommended limitations are based on SIP's and on performance information available in early 1979. It is anticipated that several additional SIP regulations covering these sources will be promulgated and/or modified in 1979 and 1980 and that appreciable new performance data will become available in the near term. Conceivably, some SIP regulations may be more stringent than the LAER suggested herein. Furthermore, performance testing may show that more stringent limits that those suggested are feasible or it may show that the suggested limits are appropriate or that they are not achievable for some specific subcategories. In any case, the basis for determining LAER for many source categories is expected to change frequently. Since LAER is near the vanguard of control technology, a more detailed analysis is particularly necessary when addressing modified or reconstructed facilities subject to the provisions of Section 173 of the Clean Air Act. Emission limitations reasonable for new sources may in some instances be economically or technically unreasonable when applied to modified or reconstructed sources of the same type.

The lowest achievable emission rate for metal furniture and large appliance coating is determined to be a combination of limitations represented by RACT and emission reductions achieved in practice. For metal furniture coating operations, LAER can be met by the use of waterborne coatings, which can achieve reductions of 88 to 92 percent. This is comparable to the RACT limitation of 360 g solvent/liter (3.0 lb/gal) of coating minus water. For large appliance coating, LAER is also equal to RACT that requires the use of a coating containing 340 g solvent/liter (2.8 lb/gal) of coating minus water. Similar reductions for these operations can be achieved by the use of other low-solvent coatings (such as powders) or higher-solids coatings. The application of add-on control devices capable of providing equivalent reductions is also an acceptable way of meeting these limitations.

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6. A series of documents referenced and summarized in: Control Strategy Preparation Manual for Photochemical Oxidant. OAQPS 1.2-047, U.S. Environmental Protection Agency. January 1977.

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3.16 MAJOR SOURCE CATEGORY: CAN COATING--VOLATILE ORGANIC COMPOUND (VOC) EMISSIONS

3.16.1 Process Description

Cans are manufactured by two different processes.[1] The three-piece can is made from a rectangular sheet and two circular ends. The metal sheet is rolled into a cylinder and soldered, welded, or cemented at the seam. One end is attached during manufacturing and the other during packaging of the product. The two-piece can is drawn and wall-ironed from a shallow cup and requires only one end, which is attached after the can is filled with product.

Two-piece can manufacturing is a high-speed process that combines the fabricating and coating operations. These cans are most commonly used by the beverage industry. Figure 3.16-1 presents a process flow diagram of fabricating and coating two-piece cans.

Metal for two-piece cans is received in coil form and is fed continuously into a press (cupper) that stamps and forms a shallow cup. The cups go through an extrusion process that, in a lubricating solution, draws and wall-irons them into cans in a lubricating solution and trims the uneven edges. The formed cans are then cleansed to remove the lubricating solution, rinsed with hot water, and dried.

The exteriors of the cans are sometimes roller coated with a base coat. The base coat is transferred from a feed tray, over a series of rollers, and onto the can, which rotates on a mandrel. The coating is cured or baked at 177° to 204°C (350° to 400°F) in single or multipass continuous ovens at a rate of 500 to 2000 cans per minute.

Designs and lettering are transferred to the cans from a printing blanket on a rotary printer. A protective varnish is sometimes roll coated directly over the inks on the same line. The decorative coating and varnish are cured or baked in single or multipass continuous, high-production ovens at 163° to 204°C (325° to 400°F).

After printing, the cans are necked, flanged, and tested. The cans are spray coated on the interior and spray and/or roll coated on the exterior of the bottom end. The coating is usually cured or baked in a continuous,

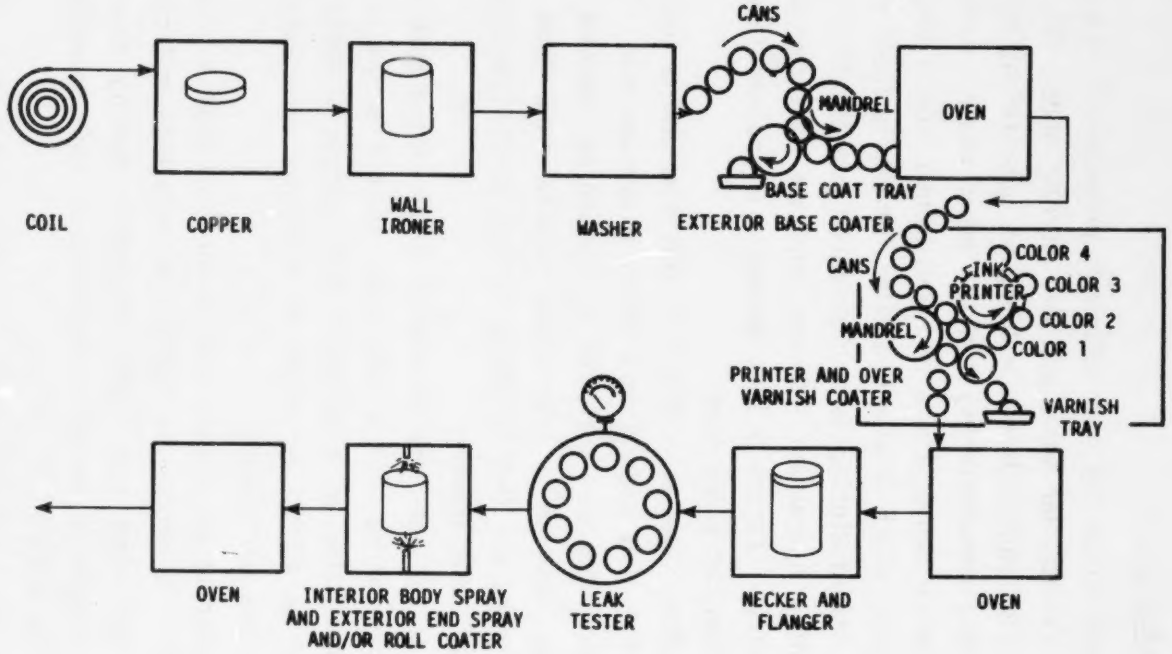
CANS
COIL
COPPER
WALL IRONER
WASHER
MANDREL
OVEN
BASE COAT TRAY
EXTERIOR BASE COATER
CANS
INK
PRINTER
COLOR 4
COLOR 3
COLOR 2
COLOR 1
MANDREL
PRINTER AND OVER VARNISH COATER
VARNISH TRAY
OVEN
NECKER AND FLANGER
LEAK TESTER
INTERIOR BODY SPRAY AND EXTERIOR END SPRAY AND/OR ROLL COATER
OVEN

Figure 3.16-1. Two-piece can fabricating and coating operation.

singlepass oven at temperatures of 107° to 204°C (225° to 400°F). Coated cans are stacked on pallets for shipment to users.

The three-piece can manufacturing process consists of two major operations: sheet coating and can fabricating. The sheet coating operation consists of base coating and printing, which includes the overvarnish coat.

The sheets are roll coated on one side only by transfer of the coating through a series of rollers from the coating tray onto the sheets. Sheets are then picked up by preheated wickets and transported through a continuous, multizone oven at rates of 50 to 150 sheets per minute, depending on the type of coating. The coating is cured at temperatures up to 218°C (425°F); sheets are air cooled in the last zone of the oven. Oven exhaust rates usually range between 0.94 and 6.6 Nm^3/s (2000 and 14,000 scfm).

The sheet printing or lithograph operation usually involves applying one or two colors of ink on the exterior base coat, or directly on the metal. Inks are applied by a series of rollers that transfer the design first to a blanket cylinder, then onto the metal sheet, as shown in Figure 3.16-2. Varnish is applied directly over the wet inks by a direct-roll coater. Inks and overvarnish are cured in a wicket oven similar to, but usually smaller than, the base coat oven; exhaust rates are 0.7 to 3.8 Nm^3/s (1500 to 8000 scfm). If the design requires more than two colors, the first set of inks is dried in an oven before additional color inks are applied. After all inks are applied, the sheets are overvarnished and then cured in another oven.

The three-piece cans are fabricated by forming the can bodies from coated sheets. This process includes a side-seam spray to protect the soldered seam and an inside spray to protect the inside surfaces. These processes are not considered in this guidance document.

3.16.2 Emission of Pollutants

Two significant emitting facilities at can manufacturing plants are the base coating line and the overvarnish coater/oven portion of the printing line. On each of these lines emissions are generated from both a roller coater and an oven. Uncontrolled VOC emissions from the line for base coating of sheets (three-piece cans) average 50.8 kg/h (112 lb/h); emissions from

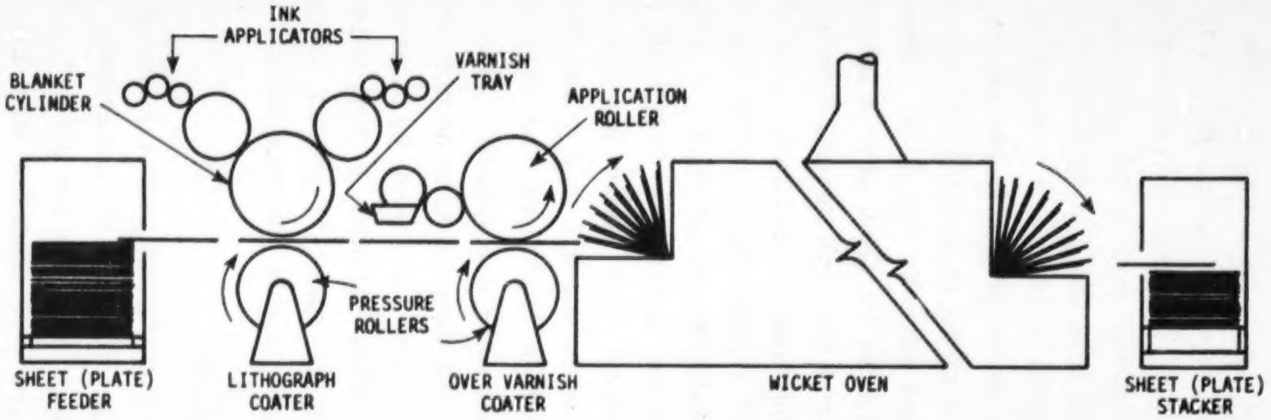
INK APPLICATORS
BLANKET CYLINDER
VARNISH TRAY
APPLICATION ROLLER
PRESSURE ROLLERS
SHEET (PLATE) FEEDER
LITHOGRAPH COATER
OVER VARNISH COATER
WICKET OVEN
SHEET (PLATE) STACKER

Figure 3.16-2. Sheet printing operation.

printing of sheets average 29.5 kg/h (65 lb/h).[1] Typical combined emissions from base coating and overvarnishing on a two-piece can coating line are 39 kg/h (86 lb/h).[1] These emissions may range from 9.1 to 270 kg/h (20 to 600 lb/h) uncontrolled, depending on the line size and speed and the type of coating.[2]

When solvent-borne sheet coatings are applied by roller, 8 to 27 percent of the coating line emissions occur in the coater area and 73 to 92 percent are from the oven. It has been suggested that as little as 20 percent of the solvent is emitted in the oven. (In two-piece exterior coating lines, up to 88 percent of the emissions occur in the coater area before the can bodies enter the oven.) The oven emissions are low in concentration of solvent per unit of exhaust (most can coating ovens are designed to operate at 25 percent of the lower explosive limit (LEL) and can be incinerated.

The spray coating of the side seams and can interior, end sealing, end spraying or roll coating (exterior), coating storage, and cleaning operations, are not considered in this document. Waterborne interior and end sealing coatings are available for some applications. The contact between these coatings and the canned product must be taken into account.

3.16.3 Control Measures

The two principal control measures utilized in the can industry coating lines are low solvent coating materials and fume incinerators.

The two types of fume incinerators are thermal incinerators, operating in the temperature range of 649° to 760°C (1200° to 1400°F), and catalytic incinerators, operating in the temperature range of 343° to 510°C (650° to 950°F). Thermal incinerators operate typically at 90 percent efficiency of hydrocarbon control (across the device) with reported values up to 98 percent efficiency, dependent upon the specific installation and coating materials being used.[1,3,4,5] Catalytic incinerators have reported control efficiencies (across the device) of 90 percent.

Fume incinerators have been used with coating materials and can coating lines with high solvent to solids content ratios.

If the coater area (the point of application of the coating material) were enclosed and the emissions combined with those from the oven, a high percentage of the coating line emissions would be directed to the fume incinerator. This has reportedly been attempted at only one plant, because the industry feels that enclosures hinder control and operation of the coaters.

Reduction of organic emissions from the point of application of the coating material by the use of low solvent coatings (waterborne and/or high solids) is 60 to 90 percent, dependent upon the particular type of coating line and the solvent content of the coating materials that would otherwise be used. The use of low solvent coating materials, as compared to high solvent coating materials, eliminates some of the concern over controlling fugitive emissions. Powder coating systems have limited potential application to exterior base coats, interior body sprays, and overvarnish. They are essentially 100 percent solids and therefore produce no organic solvent emissions.[6]

Waterborne coatings contain a polymer or resin base, water, an organic cosolvent, and a solubilizing agent. The organic cosolvent improves stability and flow-out, depresses foaming action, and controls the drying rate. High-solids coatings, with 70 to 80 percent solids by weight, may be difficult to apply because the material is highly viscous. A heating unit may be used to raise the application temperature and thereby reduce viscosity. Powder coatings require a different type of application equipment. Powder coating technology has not yet been developed to the point that thin, continuous films can be produced at high line speeds, as with solvent or waterborne coatings.

Although waterborne, high-solids, and powder coatings are comparable in performance to solvent-borne coatings in some applications in the can industry, they are not available to replace many of the present solvent-borne formulations. Therefore, this control option is not universal. The availability of low-solvent coatings should increase substantially in the next several years, however. The can coating industry will require extensive testing of these new coatings to determine their effects on the manufacturing and packaging processes and on the canned product.

Ultraviolet-curable inks are cured with a UV light source such as mercury vapor lamps. Although these are totally organic, very little vaporization occurs during the almost instantaneous curing. Therefore, UV-curing can reduce VOC emissions by nearly 100 percent (there may be slight volatilization of low-molecular-weight compounds).[1] This technology is currently limited to application of thin, semitransparent coating films and operations that would normally require oven drying between applications of ink colors. UV curing is being investigated for single-pass curing of base coat, inks, and overvarnish coat for both sheet and two-piece beverage cans.

Inks requiring no overvarnish are currently in use. These "No-Var" inks are cured by exposure to ultraviolet light. When "No-Var" inks are used, solvent emissions from overvarnish are eliminated and a great deal of energy is saved in comparison to conventional oven curing of inks and overvarnish.

3.16.4 Emission Limits

The initial criterion for defining LAER for a surface coating industry is the degree of emission control required by the most stringent state regulation.

Most organic solvent emission regulations are patterned after what is now Rule 442 of the South Coast (California) Air Quality Management District.[7] Review of regulations applicable in the 16 states that contain about 85 percent of all surface coating industries showed that they are essentially the same as Rule 442.[8] Indiana has the most stringent regulation, which limits organic solvent emissions to 1.4 kg/h or 6.8 kg/day (3 lb/h or 15 lb/day) unless such emissions are reduced by at least 85 percent, regardless of the reactivity or temperature of the solvent. Organic solvents that have been determined to be photochemically unreactive or that contain less than specified percentages of photochemically reactive organic materials are exempt from this regulation.

California Air Resources Board has recently adopted a model rule for the control of VOC emissions from can and coil coating operations.[9] This model rule, which must be met 3 years from the date of adoption, limits VOC emissions from 3-piece sheet base coating and overvarnish to 180 g solvent/ liter (1.5 lb/gal) of coating minus water, and from 2-piece base coating and overvarnish to 250 g solvent/ liter (2.1 lb/gal) of coating minus water. These limits can be achieved by the use of low solvent coatings or with add-on control equipment.

In defining LAER for surface coating emissions, it is not appropriate to exempt solvents on the basis of their reactivity. Recent research has indicated that substituting low-reactivity solvents for higher-reactivity solvents may improve photochemical oxidant air quality in one city while worsening it in downwind regions.[10] Accordingly, EPA has adopted a policy emphasizing the need for "positive reduction techniques" rather than substitution of compounds.[7]

Emission controls achieved in practice for can coating exceed regulatory requirements by a wide margin. Therefore, it is concluded that LAER for can coating is a function of controls achieved in practice rather than controls required by current regulations.

3.16.5 Determination of LAER

The recommended limitations are based on SIP's and on performance information available in early 1979. It is anticipated that several additional SIP regulations covering these sources will be promulgated and/or modified in 1979 and 1980 and that appreciable new performance data will become available in the near term. Conceivably, some SIP regulations may be more stringent than the LAER suggested herein. Furthermore, performance testing may show that more stringent limits than those suggested are feasible or it may show that the suggested limits are appropriate or that they are not achievable for some specific subcategories. In any case, the basis for determining LAER for many source categories is expected to change frequently. Since LAER is near the vanguard of control technology, a more detailed analysis is particularly necessary when addressing modified or reconstructed facilities subject to the provisions of Section 173 of the Clean Air Act. Emission limitations reasonable for new sources may in some instances be economically or technically unreasonable when applied to modified or reconstructed sources of the same type.

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3.16.4 Emission Limits

The initial criterion for defining LAER for a surface coating industry is the degree of emission control required by the most stringent state regulation.

Most organic solvent emission regulations are patterned after what is now Rule 442 of the South Coast (California) Air Quality Management District.[7] Review of regulations applicable in the 16 states that contain about 85 percent of all surface coating industries showed that they are essentially the same as Rule 442.[8] Indiana has the most stringent regulation, which limits organic solvent emissions to 1.4 kg/h or 6.8 kg/day (3 lb/h or 15 lb/day) unless such emissions are reduced by at least 85 percent, regardless of the reactiv ity or temperature of the solvent. Organic solvents that have been determined to be photochemically unreactive or that contain less than specified percentages of photochemically reactive organic materials are exempt from this regulation.

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The lowest achievable emission rate for sheet facecoating and overvarnish and two-piece can (exterior) basecoating and overvarnish is determined to be a combination of limitations represented by RACT and emission reductions achieved in practice. The LAER can be met by the use of waterborne coat ings, which can achieve reductions of 88 to 92 percent. This is comparable to the RACT limitation of 340 g solvent/liter lb/gal) of coating minus water. Similar reductions can be achieved by the use of other low-solvent coatings (such as powder) or higher-solids coatings. The application of add-on control devices capable of providing equivalent reductions is also an acceptable way of meeting these limitations.

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3.17 MAJOR SOURCE CATEGORY: METAL COIL COATING--VOLATILE ORGANIC COMPOUND (VOC) EMISSIONS.

3.17.1 Process Description

Coil coating is the coating of any flat metal sheet or strip that comes in rolls or coils.[1] The metal is typically roll coated on one or both sides on a continuous production line. The metal may also be printed or embossed. The coated metal is slit and fabricated by drawing, stamping, roll forming, or other shaping operations into finished products to be used for cans, appliances, roof decks, shelving, industrial and residential siding, cameras, culvert stock, cars, gutters, and many other items.

On some lines, the metal is uncoiled at one end of the line and recoiled at the opposite end. On other lines, called "wraparound" lines, the metal is uncoiled and recoiled at about the same point on the line. Some coil coating lines have a single coater and one curing or baking oven; others, called "tandem" lines, have several successive coaters, each of which is followed by an oven so that several different coatings may be applied in a single pass. Figure 3.17-1 is a schematic of a tandem coil coating line.

The metal is moved through the line by power-driven rollers. It is uncoiled as the process begins and goes through a splicer, which joins one coil of metal to the end of another coil for continuous, nonstop production. The metal is then accumulated so that, during a splicing operation, the accumulator rollers can descend to provide a continuous flow of metal throughout the line. The metal is cleaned at temperatures of 49°C to 71°C (120°F to 160°F), brushed, and rinsed to remove dirt, mill scale, grease, and rust before coating begins. Pretreatments, varying with the type of metal being coated and the type of coating being applied, are then applied to the metal to protect against corrosion and provide proper coating adhesion.

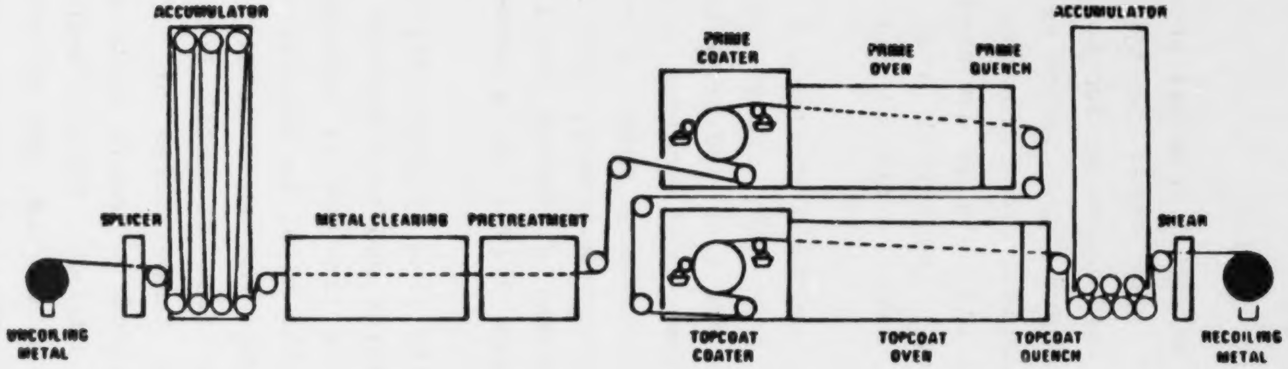
UNCOILING METAL
SPLICER
ACCUMULATOR
METAL CLEANING
PRETREATMENT
PRIME COATER
PRIME OVEN
PRIME QUENCH
TOPCOAT COATER
TOPCOAT OVEN
TOPCOAT QUENCH
ACCUMULATOR
SHEAR
RECOILING METAL

Figure 3.17-1. Diagram of coil coating line.

The first or prime coat may be applied on one or both sides of the metal by a set of three or more power-driven rollers. The pickup roll, partially immersed in the coating, transfers the coating to the applicator roll. The metal is coated, typically in a reverse roll fashion, as it passes between the applicator roll and the large backup roll. A third roll, called a "doctor" roll, may be used to control film thickness when applying a high viscosity coating by making contact with the pickup roll.

The applied coating is usually dried or baked in a continuous, multizone, high production catenary, flotation, or double-pass oven. The temperatures of the preheat, drying, or baking zones may range from 38°C to 538°C (100°F to 1000°F) depending on the type and film thickness of coating used and the type of metal being coated. The flow rates of exhaust from the ovens range from approximately 1.9 Nm^3/s to 12.3 Nm^3/s (4000 scfm to 26,000 scfm). Many of these ovens are designed for operation at 25 percent of the room-temperature lower explosive level when coating at rated solvent input. As the metal exits the oven, it is cooled in a quench chamber by a spray of water or a blast of air and then is water-cooled.

A second coat or topcoat may be applied and cured in a manner similar to the prime coat. The topcoat oven, however, is usually longer than the prime coat oven and contains more zones.

Another method of applying a prime coat on aluminum coils or a single coat on steel coils is to electrodeposit a waterborne coating to one or both sides of the coil. The coil enters a V-shaped electrocoating bath that contains a roll on the bottom. As the metal goes around the roll, electrodes on each side can be activated to permit coagulation of the paint particles on one or both surfaces of the coil. The coated coil is then rinsed and wiped by squeegees to remove the water and excess paint particles. With steel coils, the electrodeposited coating must be baked in an oven. With aluminum coils, however, the prime coat is stable enough that the metal can be passed immediately over rolls to the topcoat coater without destroying the finish and then can be baked as a two-coat system.

After cooling, the coated metal passes through another accumulator, is sheared at the spliced section, waxed, and finally recoiled. The accumulator rolls rise during the shearing process, collecting the coated metal to ensure continuous production.

3.17.2 Emissions of Pollutants

Emissions from a coil coating line come from the coating area, the preheat and baking zones of the oven, and the quench area. These emissions are mainly volatile organics and other compounds, such as aldehydes, that result from thermal degradation of volatile organics. Emissions from the combustion of natural gas, the fuel used most commonly to heat the ovens, are carbon monoxide, unburned fuel, nitrogen oxides, and aldehydes. When fuel oil is used to heat the ovens, sulfur oxides and greater quantities of nitrogen oxides and particulates will be emitted.

Of the uncontrolled organic vapors emitted from the coil coating line, the oven emits approximately 90 percent, the coater area approximately 8 percent, and the quench area the remaining 2 percent. Only these organic vapors are of concern in this document.[2,3]

3.17.3 Control Measures

Three types of control measures have been widely applied to coil coating operations: thermal incineration, catalytic incineration, and reformulation from solvent-based to water-based or high-solids coatings.

Thermal incinerators, successfully used in many coil coating facilities, have achieved organic emission reduction efficiencies of 90 to 99 percent, depending on the specific operation.[4,8] The overall plant reduction in emissions depends on the VOC capture efficiency at the coating application area. The coating area can be enclosed, and essentially all of the organic vapors can be captured and vented to the incinerator. As a minimum, 96 percent of the vapors from the coating line should be subject to collection--100 percent of oven emissions plus 60 percent of emissions from the coater and quench areas. Table 3.17-1 presents typical emissions based on assumed control efficiencies for various coil coating operations.

Many coil coating facilities are currently using catalytic incinerators to reduce organic emissions and are achieving reduction efficiencies of 85 to 95 percent, depending on the specific operation.[4,5]

Reformulation of coatings is from organic solvents to waterborne or high-solids coatings. Waterborne coatings have been successfully applied, within limits, to several coating lines and have reduced organic emissions by 70 to 95 percent, depending on the processes and the solvent level of the original solvent-borne coating.[1,9] High-solids coatings have only recently seen significant use in the coil coating industry, but progress is being made in commercializing coatings with medium-high to high-solids content. Table 3.17-2 lists the potential percentage reduction, in pounds of organic solvent per unit volume of coating, that can be realized by converting to waterborne and high-solids coatings.

The options, however, are limited. There is a lack of waterborne and high-solids coatings equivalent to organic-solvent-borne coatings for many applications, especially where resistance to corrosion or wear is critical, or where forming operations are severe. Some coatings used in the industry can poison incinerator catalysts. Incineration, especially non-catalytic, will increase the use of natural gas or other fuels if no nearby operations can use the recovered energy. This latter

TABLE 3.17-1. EMISSIONS FROM COIL COATING OPERATIONS

[Emission rates in kg/h (lb/h)][4]

Type of operation	Typical uncontrolled	Incineration[a]	Controlled catalytic combustion[b]
Duct work	145.6 (320.6)	1.5 - 14.6 (3.2 - 32.1)	7.3 - 21.8 (16.0 - 48.1)
Canopies and awning	83.99 (185.0)	0.86 - 8.40 (1.9 - 18.5)	4.2 - 12.6 (9.3 - 27.8)
Fencing	29.5 (64.9)	0.32 - 2.9 (0.7 - 6.5)	1.5 - 4.4 (3.2 - 9.7)
Screening	20.6 (45.4)	0.23 - 2.0 (0.5 - 4.5)	1.0 - 3.1 (2.3 - 6.8)
Gutters	12.9 (28.5)	0.14 - 1.3 (0.3 - 2.9)	0.6 - 2.0 (1.4 - 4.3)
Metal doors, excluding garage doors	7.63 (16.8)	0.091 - 0.77 (0.2 - 1.7)	0.4 - 1.1 (0.8 - 2.5)

[a] Based on 90 to 99 percent control.

[b] Based on 85 to 95 percent control.

TABLE 3.17-2. POTENTIAL REDUCTIONS FROM USE OF WATERBORNE AND HIGH-SOLIDS COIL COATINGS[1]

Coating formulation, by volume	kg of organic solvent per m^3 of coating minus water	(Pounds of organic solvent per gallon of coating minus water)	Potential reduction by using waterborne coatings, %
Waterborne 32% solids 54.4% water 13.6% organic solvents	264	(2.2)	
Organic solvent-borne 20% solids 80% solvent	708	(5.9)	90
50% solids 50% solvent	444	(3.7)	58
70% solids 30% solvent	264	(2.2)	0

limitation has been overcome through the use of total energy recycling.[6,8,10]

3.17.4 Emission Limits

The initial criterion for defining LAER for a surface coating industry is the degree of emission control required by the most stringent regulation adopted and successfully enforced by a state or local air pollution control agency.

As reported elsewhere, most regulations of organic solvent emissions are patterned after what is now Rule 442 of the South Coast (California) Air Quality Management District.[11] Review of regulations in the 16 states that contain about 85 percent of all surface coating industries showed them to be essentially the same as Rule 442.[12] Indiana has the most stringent regulation in that it limits organic solvent emissions to 1.4 kg/h or 6.8 kg/day (3 lb/h or 15 lb/day) unless such emissions are reduced by at least 85 percent, regardless of the reactivity or temperature of the solvent. Organic solvents that have been determined to be photochemically unreactive or that contain less than specified percentages of photochemically reactive organic materials are exempt from this regulation.

California Air Resources Board has recently adopted a model rule for the control of VOC emissions from can and coil coating operations.[13] This model rule, which must be met 3 years from the date of adoption, limits VOC emissions from the coil prime and topcoating or single coating line to 120 g solvent/liter (1.0 lb/gal) of coating minus water through the use of add-on control equipment, unless the solvent content of the coating used is no more than 200 g/liter (1.7 lb/gal) of coating minus water.

In defining LAER for surface coating emissions, it is not appropriate to exempt solvents on the basis of reactivity. Recent research has indicated that substituting low-reactivity solvents for higher-reactivity solvents may improve photochemical oxidant air quality in one city while worsening it in downwind regions.[11] Accordingly, EPA has adopted a policy emphasizing the need for "positive reduction techniques" rather than substitution of compounds.[11]

Emission controls achieved in practice for metal coil coating exceed regulatory requirements by a wide margin. Therefore, it is concluded that the LAER for metal coil coating is a function of controls achieved in practice rather than controls required by existing regulations.

3.17.5 Determination of LAER

The recommended limitations are based on SIP's and on performance information available in early 1979. It is anticipated that several additional SIP regulations covering these sources will be promulgated and/ or modified in 1979 and 1980 and tht appreciable new performance data will become available in the near term. Conceivably, some SIP regulations may be more stringent than the LAER suggested herein. Furthermore, performance testing may show that more stringent limits than those suggested are feasible or it may show that the suggested limits are appropriate or that they are not achievable for some specific subcategories. In any case, the basis for determining LAER for many source categories is expected to change frequently. Since LAER is near the vanguard of control technology, a more detailed analysis is particularly necessary when addressing modified or reconstructed facilities subject to the provisions of Section 173 of the Clean Air Act. Emission limitations reasonable for new sources may in some instances be economically or technically unreasonable when applied to modified or reconstructed sources of the same type.

Incineration efficiencies of 98 to 99 percent have been documented and are attainable for coil coating operations where thermal incinerators (afterburners) are used.[6,8] Incineration efficiencies of 95 percent have been attained for operations utilizing catalytic incineration. As discussed earlier, overall control efficiency also depends on VOC collection efficiency. All of the oven exhaust can be directly vented to the control device, and if the coating area is enclosed, essentially all of the VOC emissions from this facility can also be captured for incineration. Switching to waterborne or highsolids coatings will eliminate some of the concern over collection of solvent emissions since the organic content is substantially reduced. The derivation of an equivalent waterborne coating followings:

Overall control = 96% collection, 97% reduction
= 93%

Assuming a typical coating contains 25 percent solids,
100 gallons of coating contains 25 gallons solids
75 gallons solvent

Reducing the solvent by 93% = (75) - [0.93 (75)] = 5.3 gallons of solvent allowed

Assuming a solvent density of 7.36 lb/gallon, 5.3 gallons = 39 lbs of solvent.

Equivalent coating required = 39 lb of solvent/(25 + 5.3) gallons coating munus water
= 1.3 lb of solvent/gallon coating minus water
= 155 g of solvent/liter coating minus water

The best controlled systems consist of an enclosed coating area and a thermal incinerator. The use of a heat recovery system on this type of operation has the additional capability of actually reducing the fuel usage in the plant up to 87 percent.[6] Therefore, it may be concluded that the lowest achievable emission rate for a coil coating line (coating application area and oven) is an efficient VOC collection scheme in conjunction with a 97 to 99 percent reduction in emissions, or use of the equivalent low-solvent coating.

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3.18 MAJOR SOURCE CATEGORY: PAPER COATING-- VOLATILE ORGANIC COMPOUND (VOC) EMISSIONS

3.18.1 Process Description

Paper is coated for a variety of decorative and functional purposes by applying waterborne, organic-solvent-borne, or solventless extrusion materials.[1] Products with coatings that incorporate organic solvents include adhesive tapes and labels, decorated paper, waxed paper, book covers, office paper, carbon paper, typewriter ribbons, and photographic films.

Figure 3.18-1 shows a typical paper coating line. Components include an unwind roll, a coating applicator, an oven, various tension and chill rolls, and a rewind roll. Coatings may be applied to paper in several ways. The main applicators are knives, reverse rollers, or rotogravure devices. A knife coater consists of a blade that scrapes excess coating from the paper, as shown in Figure 3.18-2. The position of the knife can be adjusted to control the thickness of the coating. The reverse roll coater applies a constant thickness of coating to the paper, usually by means of three rollers, each rotating in the same direction, as shown in Figure 3.18-3. A transfer roll picks up the coating solution from a trough and transfers it to a coating roll. A "doctor" roll removes excess material from the coating roll, thereby determining the thickness of the coating. A rubber backing roll supports the paper web at the point of contact with the coating roll, which is rotating in a direction opposite to that of the paper. Rotogravure is usually considered a printing process--the coating is picked up in a recessed area of the roll and transferred directly to the substrate.

Ovens range from 6.1 to 61 m (20 to 200 ft) in length and may be divided into two to five temperature zones. The first zone, where most of the solvent is evaporated, is usually at a low temperature 43.3°C (≃110°F). Other zones are maintained at progressively higher temperatures to cure the coating after most

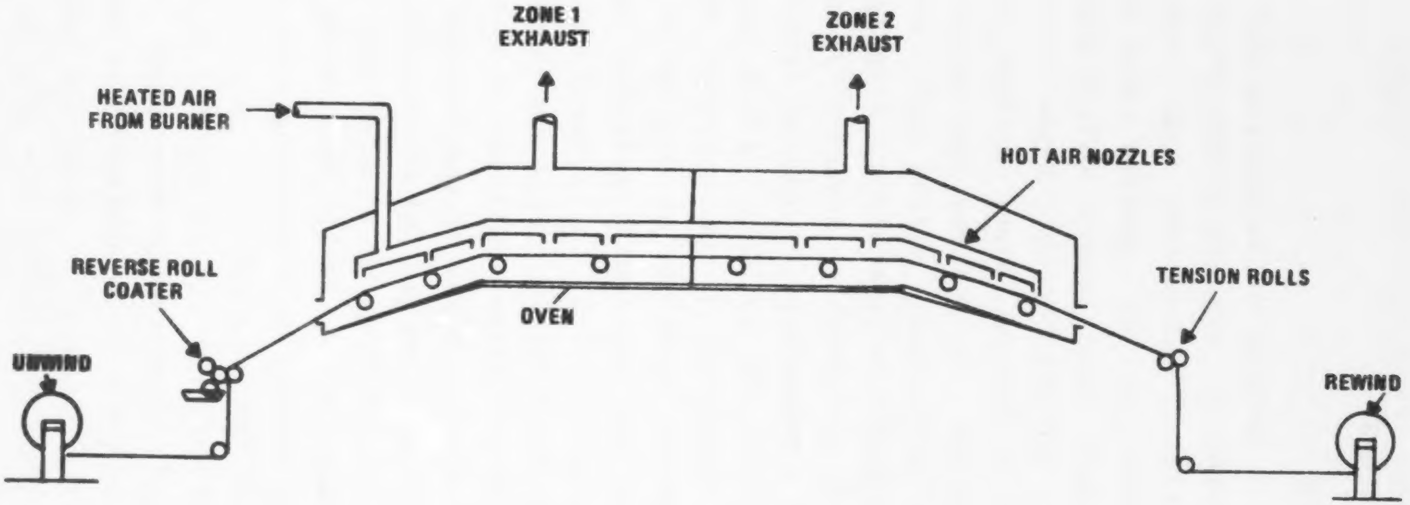
ZONE 1
EXHAUST
ZONE 2
EXHAUST
HEATED AIR
FROM BURNER
HOT AIR NOZZLES
REVERSE ROLL
COATER
OVEN
TENSION ROLLS
UNWIND
REWIND

Figure 3.18-1. Typical paper coating line.

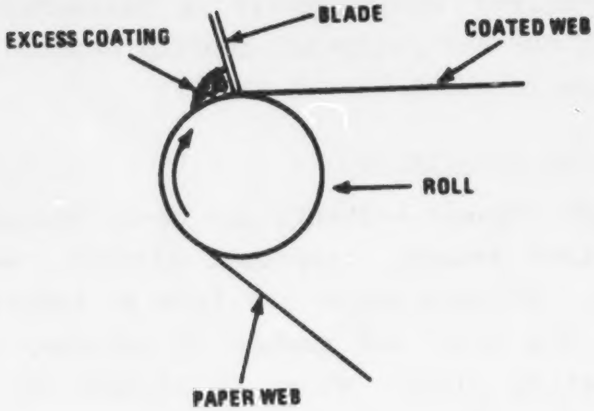
BLADE
EXCESS COATING
COATED WEB
ROLL
PAPER WEB

Figure 3.18-2. Knife application technique for coating paper.

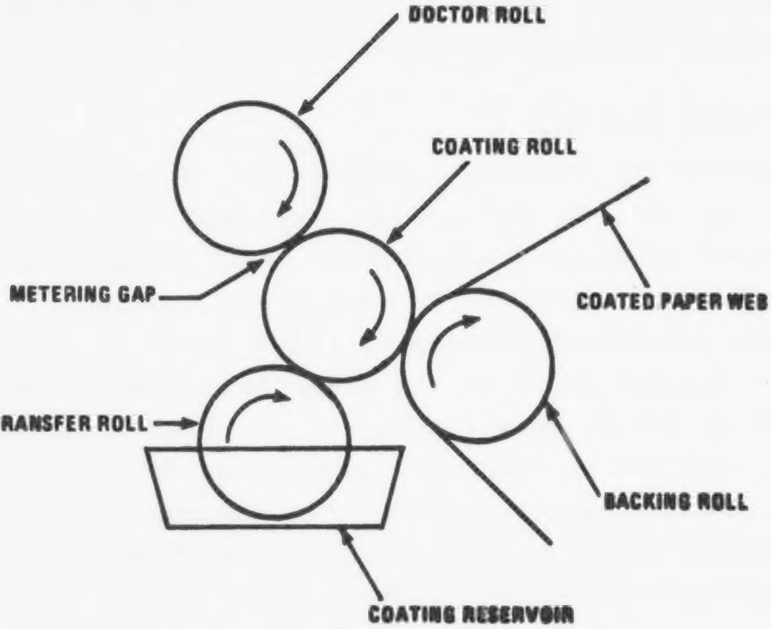
DOCTOR ROLL
COATING ROLL
METERING GAP
COATED PAPER WEB
TRANSFER ROLL
BACKING ROLL
COATING RESERVOIR

Figure 3.18-3. Reverse roll application technique for coating paper.

of the solvent has evaporated. Exhaust streams from different zones may be discharged independently or collected in a common header in front of the air pollution control device. The average exhaust temperature is about 93.3°C (200°F).

3.18.2 Emissions of Pollutants

Many different organic solvents are used, including toluene, xylene, methyl ethyl ketone, isopropyl alcohol, methanol, acetone, and ethanol. Solvent emissions from an individual coating plant vary with the size and number of coating lines. In a typical paper coating plant, about 70 percent of all solvents used are emitted from the coating line. Uncontrolled emissions from a single line may vary from 2.3 to 454 kg/h (50 to 1000 lb/h), depending on the line size. A coating line consists of a coating applicator and a drying oven, the two significant emitting facilities.

The remaining 30 percent of plant emissions are from sources such as solvent transfer, storage, and mixing operations.

3.18.3 Control Measures

Reductions in solvent emissions of 80 to 99 percent are achievable by use of low-solvent coatings, as shown in Table 3.18-1. These coatings form organic resin films with properties equal to those of typical solvent-borne coatings. Waterborne coatings are two-phase systems in which water is the continuous phase and a polymer resin is the dispersed phase. When the water is evaporated, the polymer coating is cured and forms a film with properties similar to those of organic-solvent-borne coatings. Plastisols usually contain little or no solvent, although solvent is occasionally added to improve flow characteristics. Hot-melt coatings contain no solvent. The polymer resins are applied to the paper surface in a molten state, and all materials deposited on the paper remain as part of the coating. A plastic extrusion

TABLE 3.18-1. SOLVENT EMISSION REDUCTIONS ACHIEVABLE BY USE OF LOW-SOLVENT COATINGS IN THE PAPER COATING INDUSTRY[1]

Type of low-solvent coating	Reduction achievable, %[a]
Waterborne coatings	80-99
Plastisols	95-99
Extrusion coatings	99+
Hot-melts	99+
Pressure-sensitive adhesives	
Hot-melt	99
Waterborne	80-99
Prepolymer	99
Silicone release agents	
Waterborne emulsions	80-99
100 percent nonvolatile coatings	99+

[a] Based on comparison with a conventional coating containing 35 percent solids by volume and 65 percent organic solvent by volume.

coating is a type of hot-melt coating in which a molten thermoplastic sheet is discharged from a slotted dye onto a paper substrate. The moving substrate and molten plastic are combined in a nip between a rubber roll and a chill roll. Prepolymer adhesive coatings are applied as a liquid composed of monomers containing no solvent. The monomers are polymerized by either heat or radiation. Although these prepolymer systems show promise, they are only in a developmental stage.

Carbon adsorption systems can be 97 to 98 percent efficient in controlling organic solvent vapors that are drawn into the carbon bed.[2,3] Carbon adsorption has been used since the 1930's for collecting solvents emitted from paper coating operations, mainly because it is profitable to reclaim the emitted solvent. The efficiency of control equipment operation depends largely on inlet solvent concentration; with an inlet concentration of 1000 ppm toluene, the achievable control efficiency is 97 percent, whereas with an inlet concentration of 3000 ppm it is practicable to achieve control efficiencies of 98 percent.[2] These control efficiencies pertain to the control equipment only and do not reflect the efficiency of solvent capture and emission delivery to the control device. Essentially all of the emissions from this area can be captured with hoods. Solvent recovery in the range of 96 percent of the solvent introduced to the coating line has been demonstrated.[1,4]

Thermal incinerators may be used to control organic vapors. Catalytic incinerators have rarely been applied in paper coating operations using roll or knife coaters, but certainly are applicable. Incinerators operating at high temperatures can be up to 99 percent efficient in controlling organic vapors directed to the incinerator.[5] Although no documentation has been acquired, industry sources have stated that high efficiencies (98 to 99 percent across the device) are achievable by use of an afterburner in a paper coating plant. Overall facility control would be less because of emissions that escape capture.

Incinerators and carbon adsorbers are the two proven add-on control devices for controlling organic solvent emissions from paper coating lines. Both have been retrofitted onto paper coating lines and are being operated successfully. The main constraint on the use of incinerators is the possible shortage of natural gas. Often the combination of afterburner and oven, however, uses no more fuel than the oven alone, with proper heat recovery.[6] The major disadvantage of carbon adsorption is that some solvent mixtures may not be economically recoverable in usable form. If the solvent can be recovered for reuse, carbon adsorption represents an economic advantage.

Control of solvent emissions from such sources as transfer, storage, and mixing operations requires that solvent-containing vessels be equipped with tight-fitting covers that are kept closed. Areas frequently cleaned with solvent should be equipped with hoods to capture solvent fumes, which are then ducted to a control device. Solvent-soaked rags should be kept in closed containers.

3.18.4 Emission Limits

Initial criterion for defining lowest achievable emission rate (LAER) for a surface coating industry is the degree of emission control required by the most stringent regulation adopted and successfully enforced by a state or local air pollution control agency.

As reported elsewhere, most organic solvent emission regulations are patterned after what is now Rule 442 of the South Coast (California) Air Quality Management District.[7] Review of regulations applicable in the 16 states that contain about 85 percent of all surface coating industries showed them to be essentially the same as Rule 442.[8] Indiana has the most stringent regulation in that it limits organic solvent emissions to 1.4 kg/h (3 lb/h) or 6.8 kg/day (15 lb/day) unless such emissions are reduced by at least 85 percent, regardless of the reactivity or temperature of the solvent. Organic solvents that have been determined to be photochemically unreactive or that contain less than specified percentages of photochemically reactive organic materials are exempt from this regulation.

California Air Resources Board has recently adopted a model rule for the control of VOC emissions from paper and fabric coating operations.[9] This model rule, which must be met 3 years from the date of adoption, limits VOC emissions from the coating line to 120 g solvent/liter (1.0 lb/gal) of coating minus water through the use of add-on control equipment, unless the solvent content of the coating used is no more than 265 g/liter (2.2 lb/gal) of coating minus water.

In defining LAER for surface coating emissions, it is not appropriate to exempt solvents on the basis of their reactivity. Recent research has indicated that substituting low reactivity solvents for higher reactivity solvents may improve photochemical oxidant air quality in one city while worsening it in downwind regions.[10] Accordingly, EPA has adopted a policy emphasizing the need for "positive reduction techniques" rather than substitution of compounds.[7]

Emission controls achieved in practice for paper coating exceed regulatory requirements by a wide margin. Therefore, it is concluded that LAER for paper coating is a function of controls achieved in practice rather than controls required by existing regulations.

3.18.5 Determination of LAER

The recommended limitations are based on SIP's and on performance information available in early 1979. It is anticipated that several additional SIP regulations covering these sources will be promulgated and/ or modified in 1979 and 1980 and tht appreciable new performance data will become available in the near term. Conceivably, some SIP regulations may be more stringent than the LAER suggested herein. Furthermore, performance testing may show that more stringent limits than those suggested are feasible or it may show that the suggested limits are appropriate or that they are not achievable for some specific subcategories. In any case, the basis for determining LAER for many source categories is expected to change frequently.

Since LAER is near the vanguard of control technology, a more detailed analysis is particularly necessary when addressing modified or reconstructed facilities subject to the provisions of Section 173 of the Clean Air Act. Emission limitations reasonable for new sources may in some instances be economically or technically unreasonable when applied to modified or reconstructed sources of the same type.

Control efficiencies of greater than 95 percent across-the-control device have been documented and are achievable for paper coating operations in which thermal or catalytic incineration or carbon adsorption systems are used.[2,3,5] A paper coating operation can deliver at least 90 percent of the VOC emissions to a control device that yields an overall control efficiency of 85 percent; this is equivalent to the uncontrolled emissions from a low-solvent coating containing 310 g of solvent/liter (2.6 lb/gal) of coating minus water. This derivation is shown in the following calculation:[11]

Assuming a typical coating contains 22 percent solids,

100 gal of coating contains 22 gal solids

78 gal solvent

Reducing the solvent emitted yields: (78) - [0.85 (78)] = 11.7 gal permitted

Assuming a solvent density of 7.36 lb/gal, 11.7 gal = 86.1 lb solvent

Equivalent coating required = 86.1 lb solvent/(22 + 11.7) gal of coating minus water

= 2.6 lb solvent/gal coating minus water

= 310 g solvent/liter coating minus water

Although conversion to a waterborne or higher-solids coating will significantly reduce VOC emissions, it may not achieve the 310 g/liter (2.6 lb/gal) limitation, in which case control of part of the VOC emission is still recommended. Control of VOC emissions using add-on control devices providing at least 85 percent overall plant control is also acceptable.

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SECTION 4

COST ESTIMATING METHODOLOGY

4.1 INTRODUCTION

4.1.1 Purpose

The purpose of this chapter is to provide air pollution control officials and industry personnel with a method of estimating preliminary costs of air pollution control measures. The method presented herein should provide estimates accurate to within ± 20 to 30 percent for specific cases when adequate data are available.

4.1.2 Scope

A methodology for developing total installed capital cost estimates and total annualized cost estimates is presented. This is a generalized approach; specific process or equipment costs are not included herein. Emphasis is on costs of add-on control systems; however, by following the general procedure and basic principles, costs can be developed for process modifications and material or fuel substitution.

Design parameters and other factors affecting the overall cost of installing and operating control systems are discussed. Capital costs may be estimated for both new plants and retrofit situations. Annualized cost components are separately computed as operating costs, maintenance costs, capital charges, and product and energy recovery credits. Secondary environmental costs for wastewater and solid waste treatment and disposal can also be developed. An example of a cost estimation for a control system is presented, and forms are provided for actual cost estimation.

4.2 FACTORS AFFECTING THE COST OF EMISSION CONTROL

The major gas stream characteristics affecting costs and selection of equipment are the exhaust volume, pressure, temperature, moisture content, and corrosiveness. Accurate data are necessary for accurate cost estimation. Variations of these parameters, especially exhaust volume, must be studied and considered in the control design. Fluctuation in gas flow rates affect the performance of some control devices more than others. Gas conditioning equipment such as precleaners, cooling chambers, and humidifiers are required for some control options. Certain gaseous components in the gas stream, especially oxides of sulfur, require that corrosion-resistant materials be used in the control system.

The physical properties of the pollutant and the gas stream affect the control system design and hence the cost. These properties include particle size, pollutant concentration, electrical properties of the particles, and moisture content of the gas stream. Accurate data on only the basic variables, however, will enable manufacturers or suppliers to furnish costs that can be used to develop preliminary estimates of capital costs.

Process operating methods and cycles necessarily influence system design, which may affect overall costs. Age, type, and size of facility; availability of space for locating the control device; and ease of retrofitting existing facilities all affect system selection and ultimate costs.

Plant parameters such as the requirements for an availability of utilities and wastewater and solid waste treatment/disposal facilities affect the design and cost of a control system. Plant location, local climate, geography, and demography may determine more stringent emission limitations.

4.3 CAPITAL COST ESTIMATES

Total capital costs include equipment costs, direct capital costs, indirect capital costs, and contingencies. The cost estimate for a complete system will include the cost of the control device and auxiliary equipment such as fans, pumps, and duct work. Capital costs associated with wastewater and solid waste treatment/disposal facilities can also be estimated.

4.3.1 Limitations, Restrictions, and Uncertainties

The accuracy of a cost estimate for an APC system may vary from ± 20 to 30 percent (when based on preliminary design of major equipment) to ± 5 percent (when prepared from complete drawings, specifications, and site surveys).[1] The procedure outlined in this section will provide predesign estimates accurate to within ± 20 to 30 percent of actual costs if sufficient exhaust gas, emission, and operating data are available.

The use of direct cost factors without giving proper consideration of their applicability to site specifics lends uncertainty to the final estimates. The factors represent the average or typical installation, and these factors will vary with individual installations. Because 10 to 15 equipment items may be involved in a total cost estimate, however, the errors will tend to average out. The use of other factors such as material cost factors, cost-scaling exponents, and cost indices will add to the error and uncertainty of cost estimates.

4.3.1.1 Retrofitted Systems--

Because retrofitted control systems may cost considerably more (or sometimes less) than a complete system incorporated into the design of a new plant, the effect of retrofitted systems must be considered. This requires site-specific considerations such as existing duct work, physical obstruction, and process equipment configurations. The cost estimating procedure assumes that actual retrofitting requirements are known for the sources for which costs are being developed.

4.3.1.2 Process Modifications and Fuel/Material Substitution--

In some cases a process modification and/or fuel or material substitution is necessary to reduce emissions to a desired level. Examples of such process changes include combustion modification to control NO_x emissions from power boilers; the substitution of ultraviolet dryers for hot-air dryers to eliminate VOC emissions from printing operations; or the conversion of dry rock grinding to wet rock grinding to eliminate particulate emissions.

The cost methodology does not specifically give direct information required to estimate costs of process modifications. By following the general procedures, however, estimates can be developed. For example, the prices for major equipment are obtained and cost factors are applied in the same way as cost factors for add-on control devices.

4.3.2 Capital Cost Components

Total installed cost, or total capital investment, is developed from the base purchase prices of equipment items by multiplying the unit costs by individual direct labor and material cost factors and by indirect cost factors.

4.3.2.1 Equipment Cost--

Sources of cost information--An index to industrial equipment and manufacturers can be consulted to obtain companies and contacts for acquiring cost information on each individual component. Chemical Engineering Equipment Buyers' Guide[9] and other indexes, advertisements in technical journals, and the yellow pages in telephone books provide an excellent means of locating sales representatives. Capital and Operating Costs of Selected Air Pollution Control Systems, (EPA-450/3-76-014, May 1976)[2] is an excellent publication source of equipment costs.

Past purchase orders are also useful in determining equipment costs, even though they do not readily provide exact equipment size and current costs. Cost indexes and cost scaling methods can be used to determine proper costs.

A third source of cost information is actual or model cost studies for similar processes given in technical journals, trade publications, EPA documents, etc. The disadvantage of using these sources is that they are sometimes general in their treatment of processes and control systems. Many times, however, this can be a reasonable method of estimating costs, with some adjustment of the data.

Cost indexes--Since prices and labor costs vary widely from one time period to another, cost indexes are used to update equipment costs from those indicated in a previous year. One source of data on wage and price fluctuations is the Monthly Labor Review published by U.S. Bureau of Labor Statistics. The Chemical Engineering plant index (CE Index) is frequently used to extrapolate entire system costs to current or future dollars, and the Marshall and Stevens (M&S) Equipment Index can be used for specific equipment items. Table A-1 in Appendix A presents suitable cost indexes for various types of equipment. Figure 4-1 shows the trend of plant costs and construction labor cost indexes from 1957 through 1977.

EXAMPLE: The purchase price of a 500-hp fan was \$20,000 in 1962. The price of the same fan in 1975 would be estimated by multiplying the 1962 price by the ratio of 1975 Fabricated Equipment Cost Index in Appendix A to the 1962 index as follows:

$$\begin{aligned}\text{(1975 price)} &= \text{(1962 price)}\left(\frac{\text{1975 index}}{\text{1962 index}}\right)\\ &= \$20{,}000 \times \left(\frac{192}{101}\right)\\ &= \$38{,}000\end{aligned}$$

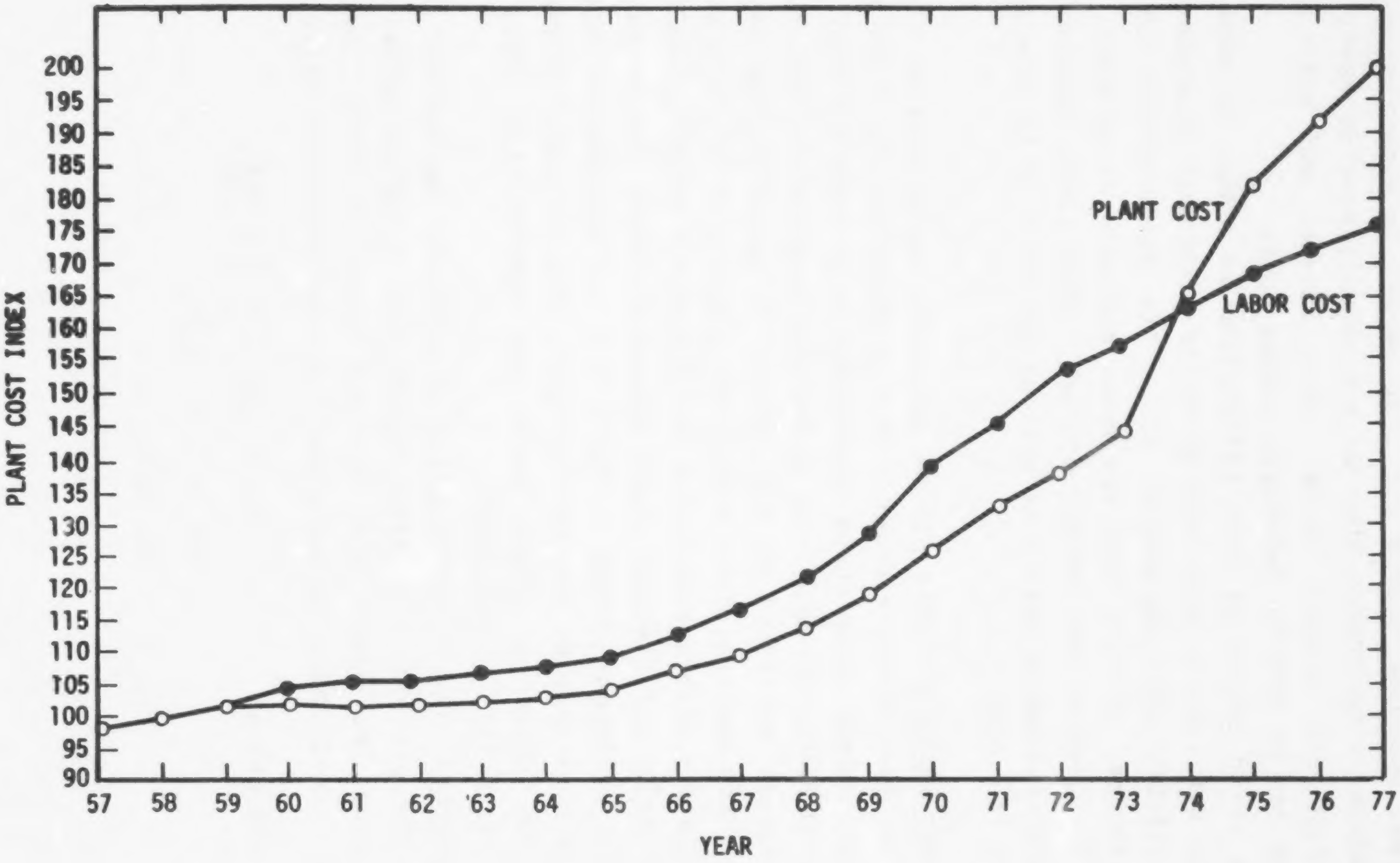

Figure 4-1. Chemical Engineering plant cost and construction labor index. (Information obtained from Reference 2.)

Scaling exponents--When the purchase price is available on an identical type of equipment of a different size, scaling exponents can be used to adjust the price to apply to equipment of the desired size or capacity. Tables 4-1, 4-2, and 4-3 present scaling exponents found in or derived from various cost sources. Size/price relationships are generally exponential and follow the equation:

$$P_A = P_B \quad \left(\frac{C_A}{C_B}\right)^x$$

Where P is the price of items A or B, C is the capacity or size, and x is the scaling exponent. The accuracy of a price estimate becomes questionable when prices are escalated to reflect more than an order of magnitude in size.

EXAMPLE: The 1965 purchase price of a fabric filter with 1000 square units of cloth area was $2500. The 1977 price of the same type of fabric filter with 2300 square units of cloth area is estimated as follows:

$$(\text{1977 price}) = (\text{1965 price}) \left(\frac{\text{1977 index}}{\text{1965 index}}\right) \left(\frac{\text{new cloth area}}{\text{old cloth area}}\right)^x$$

x = scaling exponent for fabric filter

$$(\text{1977 price}) = \$2500 \times \left(\frac{200}{103.4}\right) \times \left(\frac{2300}{1000}\right)^{0.95} = \$11{,}000$$

Material cost factors--Another type of cost factor is used to escalate the cost of an item constructed of a certain type of material (e.g., carbon steel) to the price of the same equipment item constructed of another material or in conjunction with another material (stainless steel, glass lining, insulation, Inconel, nickel-plating, etc.). Carbon steel and stainless steel are the most common materials of construction for fans, duct work, control devices, and other major equipment items. Tables 4-1 through 4-3 contain material cost factors for escalating

TABLE 4-1. COST FACTORS AND SCALING EXPONENTS FOR AIR POLLUTION CONTROL DEVICES

Control device	Direct cost factor[a]	Stainless steel factor[b]	Scaling exponents[c]	
			Unit	Exponent
Fabric filter	2.0	1.5[d]	ft^2 cloth	0.95
Electrostatic precipitator	2.0	2.4	ft^2 plate	0.37
Wet collector	3.0	2.4[e]	acfm	0.70
Cyclones	1.7[f]	2.0[e]	acfm	0.80[f]
Absorption units	3.0	2.5[g]	acfm	0.62[g]
Carbon adsorber	1.6[d]	2.5[h]	lb carbon	0.90[d]
Catalytic incinerator[d]	1.6		acfm	0.60
Thermal incinerator[d]				
with heat exchanger	1.6		acfm	0.70
without heat exchanger	1.6		acfm	0.4-0.5
Condensers	3.0		acfm	0.70[g]

[a] Considered an approximate average; cost factors could vary by up to ± 40 to 50 percent or more in some cases. Includes equipment, material and labor costs. Does not include indirect cost. Developed from PEDCo experience unless otherwise noted.

[b] Suitable for approximation of 304 or 316 type stainless steel.

[c] To escalate cost of a similar unit of a different size.

[d] Reference 2.

[e] Reference 3.

[f] Reference 4.

[g] Reference 5.

[h] Reference 1.

Table 4-2. COST FACTORS AND SCALING EXPONENTS FOR AUXILIARY EQUIPMENT ITEMS

Equipment item	Direct cost factor[a]	Stainless steel factor[b]	Scaling exponents[c]	
			Unit	Exponent
Fan system	2.0	2.8[d]	BHP	0.96
Pump system				
Reciprocating[e]	2.4	2.4	BHP	0.52
Centrifugal[e]	2.4	2.0	BHP	0.52
Drivers[e]	2.4		BHP	1.00
Chemical injection[e]	1.6	2.0	BHP	0.60
Heat exchanger (S/T)[e]	2.3	CS/SS 2.5 SS/SS 3.1	ft^2s.a.	0.70
Air cooler[e]	1.6	3.0	ft^2s.a.	0.70
Quench tower	3.0	3.3	acfm	0.85[f]
Spray chamber	2.5	3.3	acfm	0.43[f]
Reheater	3.5	2.5[d]	acfm	0.78
Ductwork	2.6	3.3[g]	ft^2c.s.a.	0.55[e,h]
Exhaust stack[e]	1.5	3.0	ft	1.0
Hoppers[e]	1.1		ft^3	0.68
Transformers[e]	1.2		kVa	0.33
Screw conveyors	1.6[e]		length, ft	0.8[e,f]

[a] Considered an approximate average; cost factors could vary by up to ± 40 to 50 percent or more in some cases. Includes equipment, material and labor costs. Does not include indirect cost. Developed from PEDCo experience unless otherwise noted.

[b] Suitable for approximation of 304 or 316 type stainless steel.

[c] To escalate cost of a similar unit of a different size.

[d] Reference 1.

[e] Reference 4.

[f] Reference 2.

[g] Reference 6.

[h] Resulting cost is expressed as dollars per linear foot of ductwork installed.

TABLE 4-3. COST FACTORS AND SCALING EXPONENTS FOR WASTEWATER AND SOLID WASTE TREATMENT EQUIPMENT

Equipment item	Direct cost factor[a]	Stainless steel factor[b]	Scaling exponent[c]	
			Unit	Exponent
Storage tanks				
Less than 40,000 gal	2.0	3.25[d]	gal	0.29[d,e]
More than 40,000 gal	2.0	3.35[d]	gal	0.63[d,e]
Clarifier	2.5		ft^2 c.s.a	0.63[f]
Vacuum filter	4.0		gpm	0.41[f]
Sludge dryer	4.0		gpm	0.45[g]
Centrifuge	3.5		gpm	0.44[f]
Rotary drum filter	1.6		ft^2 s.a.	0.63[f]
Ion exchangers	1.7[f]	2.5[h]		
Carbon adsorption	1.5[f]	2.5[h]		
Reverse osmosis units	1.7			

[a] Considered an approximate average; cost factors could vary by up to ± 40 to 50 percent or more in some cases. Includes equipment, material and labor costs. Does not include indirect cost. Developed from PEDCo experience unless otherwise noted.

[b] Suitable for approximation of 304 or 316 type stainless steel.

[c] To escalate cost of a similar unit of a different size.

[d] Reference 7.

[e] Exponents are for total installed costs.

[f] Reference 8.

[g] Reference 4.

[h] Reference 1.

carbon steel prices to stainless steel prices on control devices and auxiliary equipment. These factors are suitable for estimating 304 or 316 type stainless prices. Cost factors for other materials can be found in the cited literature.

EXAMPLE: The 1959 price of a 10-hp carbon steel centrifugal pump was $400. The stainless steel factor is 2.0 (Table 4-2). The 1977 price of a 30-hp stainless steel centrifugal pump is estimated as follows:

$$(1977 \text{ price}) = \$400 \times \left(\frac{30}{10}\right)^{0.52} \times \left(\frac{200}{102.5}\right) \times 2.0 = \$2800$$

The accuracy of this 1977 price is lessened because it is necessary to use multiple cost factors.

4.3.2.2 Direct Capital Costs--

Direct costs are those associated with the direct installation of equipment. They include materials and labor for the installation of instrumentation, electrical work, foundations, structural work, site work, insulation, painting, and piping.

The direct cost factors in Tables 4-1 through 4-3 were obtained from PEDCo experience, cost handbooks, and the cited literature. These cost factors are multiplied by the purchase price of each equipment item required to obtain the direct cost of installing that equipment item, including material, labor, and equipment cost.

The direct cost factors in these tables are considered to be average or typical; they can vary substantially from job to job. To ensure accuracy when using these factors, consideration must be given to site-specific conditions.

4.3.2.3 Indirect Capital Costs--

Indirect costs include engineering, field and labor expenses, contractor's fee, freight, offsite, spares, sales tax, and allowance for shakedown. These costs are determined by multiplying the total direct cost by the indirect cost factors presented in Table 4-4. These factors, which were developed from the cited references, are considered typical for air pollution control systems. Consideration must be given to their use for site-specific case conditions to ensure accuracy.

4.3.2.4 Contingencies--

Contingencies incorporate additional unforeseen expenses resulting from equipment breakage, inclement weather, strikes, shipment delays, and related items. Generally, these costs run between 10 and 20 percent of the combined direct and indirect costs. For the purpose of this cost estimating procedure, a contingency factor of 15 percent will be used.

4.3.2.5 Total Capital Cost--

The total capital cost is the sum of the direct capital costs, indirect capital costs, and contingencies. If possible, estimated production losses, research and development, and other related costs should be added directly to this total. Table 4-5 illustrates the complete capital cost estimating procedure.

4.4 METHODOLOGY FOR ESTIMATING ANNUALIZED COSTS

Annualized costs include direct operating costs (labor, maintenance, utilities, and raw materials) and fixed costs (overhead, property taxes, insurance, capital recovery costs). The annualized costs for operating solid waste and wastewater treatment/disposal systems associated with the emission control facilities are included. Some pollutants can be recycled to the

TABLE 4-4. INDIRECT CAPITAL COST FACTORS[1,10]

Cost item	Percent of direct cost
Interest during construction	5.0
Field labor and expenses	10.0
Contractor's fee	5.0
Engineering	10.0
Offsite	1.3
Spares	0.5
Sales tax	1.5
Start-up and shakedown	5.0
Total indirect cost	38

TABLE 4-5. CAPITAL COST ESTIMATION

Equipment item	Purchase price	Direct cost factor[a]	Direct cost[b]

Equipment cost[c] ______________________ Total direct cost[d] _______

A. Total direct costs ______________________

B. Total indirect costs at 38% (A)[e] ______________________

C. Contingencies at 15% (A + B) ______________________

Total capital costs (A + B + C) ______________________

[a] From Tables 4-1, 4-2, and 4-3.

[b] Includes equipment cost and installation, instrumentation, electrical work, foundations, structural work, site work, painting, piping, and labor.

[c] Sum of equipment purchase prices.

[d] Sum of individual direct costs.

[e] Includes engineering, contractor's fee, interest during construction, shakedown, spares, freight, taxes, offsite, and field and labor expenses.

system, used as a component of another product, or used as a fuel supplement. Whenever an economic value can be attributed to the captured pollutant, an appropriate credit must be included in computing the annualized costs.

4.4.1 Limitations, Restrictions, and Uncertainties

The estimated annualized cost may be somewhat less accurate than the estimated capital cost because the accuracy of the fixed costs depends largely on the accuracy of the estimates of capital cost and equipment life. When adequate operating and exhaust gas data are available, the estimate of the annualized cost will fall within ± 30 to 40 percent of actual costs. The annualized cost factors in this section are considered to be average or typical and consideration should be given to site-specific conditions.

4.4.2 Annualized Cost Components

A discussion of the individual annualized cost components and methodology for estimating total annualized costs are presented in this section.

4.4.2.1 Utilities--

Utilities include electricity, water, steam, fuel oil, and natural gas requirements. Annual incremental quantities are determined through the use of fan equations, heat balances, and the like. These quantities are then multiplied by the unit cost for the local area. Unit costs for utilities vary widely depending on the geographical location, user classification, and consumption rates.

4.4.2.2 Raw Materials--

Raw materials and special chemicals are required for certain control systems, e.g., activated carbon for adsorption units, adsorption chemicals, limestone for flue gas desulfurization units, and sulfur trioxide for ESP flue gas conditioning. Cost data are not presented for these materials because of the wide variety of materials used. Prices can be obtained from chemical suppliers or price catalogs. Annual consumption is determined and is multiplied by the unit cost to obtain the annual cost of raw materials. Incremental costs for fuel and material substitution are computed in the same manner.

EXAMPLE: A continuous source operation emits 16 kg/h (35 lb/h) of toluene. The adsorption rate of activated carbon is 7 percent, and the attrition rate 1 percent. The unit cost is assumed to be $1.01/kg. The carbon requirements and costs are estimated as follows:

$$16 \text{ kg/h toluene} \div \left(\frac{0.07 \text{ kg toluene}}{1.0 \text{ kg carbon}}\right) = 230 \text{ kg carbon/h}$$

$$\begin{aligned}\text{annual consumption} &= 230 \text{ kg carbon/h} \times 0.01 \times 8000 \text{ h/yr} \\ &= 18{,}400 \text{ kg}\end{aligned}$$

$$\begin{aligned}\text{annual carbon cost} &= \$1.01/\text{kg} \times 18{,}400 \text{ kg} \\ &= \$18{,}580 \text{ per year}\end{aligned}$$

4.4.2.3 Operating Labor--

Operating labor depends on the type, size, and complexity of the control system. A large, complex system such as the flue gas desulfurization system may require the continuous effort of two or three operators (2 to 3 hours of labor/hour of operation), whereas a small wet collector may require only occasional observation (0.05 to 0.1 hour of labor/hour of operation). The degree of system automation and the continuity of operation also influence operating labor requirements. Labor demands must be determined on a case-by-case basis, considering each equipment component and the overall system operation. The total man-hours per hour of operation is multiplied by the annual system operating time and labor rate to determine annual operating labor costs. Labor rates vary widely according to the geographical location.

4.4.2.4 Maintenance--

Maintenance costs include the material, labor, replacement parts, and supervision necessary to maintain the control system at the desired level of performance. These costs are sometimes very difficult to predict since they vary with the age of the system and modes of operation. Table 4-6 presents the ranges of maintenance costs for various types of control devices in terms of dollars per m^3/s (cents per acfm). These data generally correlate with data from other cost sources. The estimator must determine whether maintenance will be low, typical, or high, based on the complexity of a specific application in order to estimate the annual maintenance cost. An alternate method is given in Table 4-7 where maintenance costs are expressed as a percentage of capital investment.

The exhaust gas conditions and system complexity largely determine the degree of maintenance of control systems. For example, a flue gas desulfurization system is a highly automated and complex system that has problems associated with scaling and corrosion. High maintenance costs are expected.

A high-temperature gas stream from an electric arc furnace may have to be cooled before it enters a fabric filter. Occasional bag failure and replacement necessitate normal maintenance.

A process with ambient operating conditions and exhaust temperatures controlled by a medium-energy wet collector is an example of a simple system with little mechanization and low maintenance costs.

TABLE 4-6. ANNUAL MAINTENANCE COSTS OF CONTROL DEVICES[a]

[dollars per m^3/s (cents/acfm)][b]

Generic type	Low	Typical	High
Gravitational and dry centrifugal collectors	17 (0.8)	51 (2.4)	93 (4.0)
Wet collectors	68 (3.2)	136 (6.4)	203 (9.6)
Electrostatic precipitators			
High voltage	34 (1.6)	68 (3.2)	102 (4.8)
Low voltage	17 (0.8)	47 (2.2)	68 (3.2)
Fabric filters[c]	68 (3.2)	170 (8.0)	270 (12.8)
Afterburners			
Direct flame	102 (4.8)	203 (9.6)	340 (16.0)
Catalytic	237 (11.2)	680 (32.0)	1190 (56.0)

[a] Includes material, labor, and supervision.

[b] Reference 11; escalated to 1977 prices by Chemical Engineering Labor Cost Index.

[c] Add bag replacement cost: Assume 1- to 2-year life and $\$18/m^2$ ($\$0.50/ft^2$) cloth.

TABLE 4-7. PROCESS MAINTENANCE COSTS[a]

Type of system	Annual maintenance cost as a percent of capital investment	
	Labor	Materials
Simple[b]	1-3	1-3
Normal[c]	2-4	3-5
Complex[d]	3-5	4-6

[a] Adapted from Reference 1, p. 134.

[b] Atmospheric conditions, little mechanization.

[c] Normal operating condition; average system.

[d] Corrosive and severe operating conditions or extensive instrumentation.

4.4.2.5 Fixed Cost--

Fixed costs include capital charges, property taxes, insurance, overhead, and administrative costs. Capital charges are determined by multiplying the total capital cost of the system by the capital recovery factor. The capital recovery factor is a function of the interest rate and overall equipment life. Capital recovery factors for various interest rates and equipment lives are shown in Appendix A. A 10 percent interest rate can be used in most cases.[2] Insurance, property taxes, overhead, and other administrative costs are usually estimated at 4 percent of the total capital investment.[12]

Equipment life of pollution control devices is generally 10 to 15 years, depending upon the application. Better estimates can be obtained through equipment manufacturers and suppliers.

EXAMPLE: The following procedure is used to determine the total fixed cost of a control system requiring an initial capital investment of $1.2 million at an interest rate of 10 percent and having an overall equipment life of 22 years. The capital recovery factor for 22 years and 10 percent is 0.11401.

Therefore,

Capital recovery cost = 0.11401 ($1.2 million) = $136,800

Taxes, insurance, etc. = 0.04 ($1.2 million) = 48,000

Total fixed costs = $184,800

Product recovery and energy credits--When the capture of pollutants results in an economically recyclable, recoverable, or salable product, product recovery credits should be applied against annual costs. Sometimes such credits substantially reduce operating costs. First, the value (unit cost) of the pollutant must be determined. If the collected pollutant is recycled, the actual value can be assumed to be the final product price less processing costs. The annual amount of pollutant capture is estimated and multiplied by the net unit value to determine the product recovery credit.

Similarly, credits for energy (heat) recovery should be estimated when applicable. Heat recovery from the high temperature exhausts from incineration controls can greatly reduce operating costs.

Solid/liquid waste disposal--It is necessary to dispose of pollutants that cannot be recycled, recovered, or reused. Solid waste disposal techniques include several methods of landfilling. Liquid waste disposal methods include landfilling, incineration, dry-well injection, and ocean dumping. Selection of a disposal technique depends on the nature and quantity of the waste and geographical location. Annual costs of each method are not readily available, and a detailed discussion of these disposal methods is beyond the scope of this document. Annual costs can, however, be estimated by considering the following items:

- Expenses, capital recovery, and maintenance on capital items (trucks, land, equipment, etc.)
- Fuel costs

- Electricity costs
- Operating labor
    - stationary equipment
    - mobile equipment
- Materials (barrels, chemicals, etc.)
- Landfill fees
- Administrative costs

The cost of operating landfills ranges from \$2 to \$5/Mg of waste for small operations to \$1 to \$3/Mg for large operations.[13] If solid waste materials are hazardous, they may require special handling, such as disposal in sealed barrels. Barrels alone cost \$20 each, and hold up to 250 kg of waste. This would make disposal cost at least \$80/Mg.

Wastewater treatment--Wastewater treatment facilities at a plant may have sufficient capacity to handle any additional volume generated by an emission control system. The unit treatment cost in dollars/10^3 gallons is determined from operating records, EPA documents, or other sources, then multiplied by the incremental volume to be treated annually to estimate incremental costs.

When new or expanded wastewater treatment facilities are required, the cost of utilities, raw materials, chemicals, operating labor, and maintenance and fixed costs are incorporated in the annualized cost estimate for the overall system. These costs can be separated out from among the direct emission control costs.

4.4.3 Total Annualized Costs

Direct operating costs, fixed costs, product credits, and energy credits for the operation of air pollution control systems and secondary facilities can be summarized in a format given in Table 4-8.

TABLE 4-8. SUMMARY OF PREDESIGN ESTIMATE OF ANNUALIZED COSTS

Item	Unit cost	Quantity	Cost
DIRECT OPERATING COST			
I. Utilities			
Raw materials	$ /ton	tons/yr	
Electricity	$ /kWh	kWh	
Water	$ /10^3 gal	10^3 gal/yr	
Steam	$ /10^3/lb	10^3 lb/yr	
Gas	$ /10^6 Btu	10^6 Btu/yr	
Fuel oil	$ 10^3 gal	10^3 gal/yr	
II. Operating labor			
Direct labor	$ /man-hour	man-hours/h operation	
Supervision	15% direct labor		
III. Maintenance (see Tables 4-6, 4-7)			
Labor and materials			
Supplies			
Replacement parts			
IV. Sludge disposal	$ /ton	tons/yr	
V. Wastewater treatment	$ /10^3 gal	10^3 gal/yr	
		TOTAL DIRECT OPERATING	
FIXED COSTS			
I. Taxes, insurance, overhead, etc.	4% of total capital investment		
II. Capital recovery charges	% of total capital investment		
		TOTAL FIXED COSTS	
PRODUCT RECOVERY CREDIT	$ /ton	tons/yr	
		TOTAL ANNUALIZED COSTS	

4.5 COST-EFFECTIVENESS

The cost-effectiveness of a control technique is arrived at by comparing the degree of emission reduction with the total cost of achieving the reduction. It is expressed in dollars per unit weight of pollutant removed and is computed by dividing the total annualized cost by the total annual quantity of pollutant removed. As control efficiency improves, the quantity of emissions is reduced, but the cost of control increases. Cost-effectiveness relationships are useful in emission control decision making since several feasible systems usually are available for controlling each source of emission. Cost-effectiveness relationships vary from industry and from plant to plant within an industry.[11]

EXAMPLE: Assuming the annualized cost of an air pollution control system is estimated at \$126,000, the system captures 99 percent of the 39 kg/h of emissions generated, and total operating time is 8000 hours per year, cost-effectiveness is determined as follows:

$$\text{Amount of pollutant captured} = 0.99\ (39\ \text{kg/h})\ (8000\ \text{h/yr})$$

$$= 3.09 \times 10^5\ \text{kg/yr}$$

$$\text{Cost-effectiveness} = \frac{\$126{,}000/\text{yr}}{3.09 \times 10^5\ \text{kg/yr}}$$

$$= \$0.41/\text{kg pollutant removed}$$

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SECTION 5

FINANCIAL AND ECONOMIC ANALYSIS TECHNIQUES

5.1 INTRODUCTION

This section of the guidance document is intended as general reference for state and local agencies, to assist them in determining the economic impact upon major stationary sources that may result from application of pollution controls.

The costs incurred by the source as a result of control are assumed to be directly obtainable from the source or obtained by the procedures discussed in Section 4.

Subject to this assumption, generalized methodology will be described for evaluating the economic impact of these costs upon the source (i.e., the individual plant) that is being subjected to the control requirements.

Six techniques for performing relevant economic and financial analysis will be presented, with comments on the factors that might affect the selection of one or another of these techniques (or combination of techniques) for a given situation. These factors influencing selection of an appropriate analysis technique include the impact to be measured, the available data, the personnel and other resources available to the state or local agency for processing the data, and interaction with certain special incentive arrangements that are available for financial needs arising from pollution control.

In conjunction with the description of each analysis technique, the data that must be available with respect to the particular source in order to make proper use of that technique will be defined. This is a "feedback" situation: initial selection of a particular analysis technique will define the particular data needed. This will lead to a determination of the availability of these data, and that in turn may necessitate a change in the selection of the analysis technique. An important objective in what follows, therefore, is to clarify the relationships between the various analysis techniques and their respective data requirements.

In addition to the foregoing, consideration will be given to whether the capital needed for compliance is available to a particular source. This is only one facet of the various potential economic impacts of the costs of compliance. However, it is sufficiently fundamental to call for special highlighting.

The intent here is not to provide a textbook on economics and finance, to address a readership of financial experts, or to assume the place of a qualified analyst. Rather, the objective is to provide uncomplicated, straightforward explanations (in sufficient detail that the information can serve as the framework on which to construct practical applications) for readers not having specific background in finance.

The discussion is presented in two parts: description of the analysis techniques (5.2) and information needed to perform analysis techniques (5.3).

5.2 THE ANALYSIS TECHNIQUES

Six techniques for analysis of the economic impact of pollution control upon individual plants are presented below and detailed in Table 5-1:

1. Computation of Debt Service Coverage Ratio
2. Computation of Return on Investment (ROI) Ratio
3. Computation of Discounted Cash Flow
4. Reference to Previous Impact Studies
5. Reference to Financing Decisions by Others
6. Computation of Increase in Operating Costs or Assets

Table 5-1. COMPARISON OF ANALYSIS TECHNIQUES

Techniques	Impact Being Analyzed	Availability of Data			Limitations
		Sources (Prioritized)	Availability	Agency Level Of Effort Required	
Debt Service Coverage Ratio	Capital Availability	Plant Other Studies EPA OSHA References Census of Manufacturers Robert Morris Associates Troy Almanac Trade Associations Federal Trade Commission Periodicals	Existing Source - Moderately Easy New Source - Difficult	Moderate Extensive Forecasting Required	1) Verification of forecasts for new or expanded source. 2) Considerable error possible if measuring at arm's length.
Return on Investment (ROI) Ratio	Profitability	Plant Other Studies EPA OSHA References Robert Morris Associates Troy Almanac Federal Trade Commission Equipment Suppliers Census of Manufacturers Trade Associations Periodicals	Existing Source - Moderately Easy New Source - Difficult	Moderate Extensive Forecasting Required	1) Verification of forecasts for new or expanded source. 2) Indirectness of measure.
Discounted Cash Flow (DCF) Computation	Profitability	Plant	Existing Source - Moderately Difficult New Source - Difficult	Extensive Forecasting Required Extensive Forecasting Required	1) Verification of forecasts for all sources. 2) Considerable error possible if measuring at arm's length.

(continued)

Table 5-1 (continued).

Techniques	Impact Being Analyzed	Availability of Data			Limitations
		Sources (Prioritized)	Availability	Agency Level Of Effort Required	
Reliance Upon Previous Impact Studies	Whatever Impacts Studied Previously	EPA: Economic Analysis Branches of Offices of Air Quality Planning & Standards (Durham, NC) and Office of Water Programs (Washington, DC) OSHA	Relatively Easy	Minimum	1) Control costs magnitude may be so different that making judgments may be difficult. 2) If control costs being analyzed are additive to ones studied (rather than substituted) then judgments may be difficult. 3) Industry may not have been studied.
Financing Decision By Others	Capital Availability	Plant Dun and Bradstreet Local Industrial Directory SBA (Size Standard)	Moderately Easy If Working With Source Difficult If Doing Arm's Length Analysis	Minimum	1) If analysis is performed without having source apply then it is difficult to analyze existing source and very difficult to analyze new or expanded source.
Increase in Operating Costs or Assets Computation	Profitability	Plant	Existing Source - Moderately Difficult New Source - Difficult	Moderate Extensive Forecasting Required	1) Verification of forecasts for new sources. 2) Accuracy of allocation of overhead expenses from another part of company. 3) Indirectness of measure.

This list does not represent an exhaustive set of analysis techniques. There are others, but these six were chosen because they cover a variety of possible circumstances. The first three listed techniques are conventional tools for analysis of business financial conditions. The next two techniques are not so conventional, but are particularly applicable to pollution control impact financial conditions. The sixth technique was created for this guidance and is intended for special circumstances when it is impractical to establish net income figures for a plant.

In all these techniques it is most important to determine when the impact crosses the threshold from minimal to significant. The definition given to "significant" is that the plant will close because it is no longer able to conduct business or because continuing operation is not as profitable as other options. In several of these techniques the criteria for significant impact are well defined, e.g., necessary funds cannot be obtained for the pollution control expenditure, or the owners would be better off liquidating the plant and investing the money elsewhere rather than buying pollution control equipment. In other techniques (including some of the conventional ones), there are no widely recognized specific numerical criteria for determining significant impacts, for which the analyst may be required to use extensive judgment. Some judgments will be relatively simple and others will be difficult. Further, some techniques are more direct than others in measuring significant impact. For example, although the ROI and discounted cash flow techniques both measure profitability, ROI does not necessarily indicate the precise level at which the plant would choose to close, whereas the discounted cash flow technique does indicate such a level.

Before the six techniques are described, a definition of individual plant source is provided. A plant is the single physical location where the pollution control equipment is to be installed. It is analyzed on a stand-alone basis without regard to other operations of the company at other locations. Analysis is relatively straightforward when a plant is the whole company or a separate subsidiary of a larger company. Analysis may still be fairly straightforward when the plant is a division or a specific profit center of the company. Analysis is much more complicated when the plant is part of a division and buys and sells material from and to other plants or divisions within the corporation. The main problems in the latter case are validating company-submitted data that have not been independently audited or are not publicly available and assigning a value or transfer price to the intracompany goods in order to derive net income.

In the subsections that follow, the individual techniques are first briefly discussed. Following that is a comparison of the techniques that will aid an analyst in selection of techniques for a given situation.

5.2.1 Analysis Technique 1: Computation of Debt Service Coverage Ratio

The debt service coverage technique involves an analysis of whether or not a source can meet debt (i.e., interest and principal), lease, and long-term payment obligations, including those for the new pollution control expenditure, at the level of cash flow that exists at the source. It is therefore also a measure of the capital availability impact of a pollution control regulation.

The lending community looks to this ratio in longer-term borrowing situations to determine whether adequate funds will be available to repay debt obligations.

Cash flow from the operation includes net profit before taxes, lease, and interest payments plus depreciation. It is only out of this cash flow that payments can be made for such obligations unless the company has "unproductive" assets that it could convert to cash to buy control equipment. "Unproductive" designates assets unrelated to the nature of the business, for example, long-term marketable securities or certificates of deposit.

This technique can be applied as a verification of a financing inability determined under Technique 5 or as a prediction of whether financing may be obtainable. It can be used for a new or an existing plant. It is used primarily when the agency and the source are engaged in deliberations, since the level of obligations that are a crucial part of the analysis is highly dependent upon the particular circumstances of the plant.

The results of the debt service coverage analysis will be a ratio, the numerator of which is cash flow from operations and the denominator of which is future debt and other long-term obligations. The ratio needs to be computed on a "before" and "after" pollution control basis. In order for a financing source to loan money to a plant, the "after" ratio should exceed 1.0. Most financing sources, however, would require an ample cushion greater than 1.0 to reflect risk over time. If the "after" ratio exceeds 2.0, it can be assumed that there is no significant impact. If the ratio is between 1.5 and 2.0, chances are that the financing is still obtainable but the company is in a risk situation unless it is accustomed to operating at that ratio. A ratio between 1.0 and 1.5, for the purposes of this analysis, will be considered to indicate significant impact.

The banking industry, although using this technique extensively, does not specify a criterion to be used in making judgments. For example, a bank may grant financing in a case where the ratio is less than 1.5 because the company has historically operated at that level and has been able to meet its obligations. Thus it is important to do both before and after analyses of the ratio to indicate the extent of change of the ratio as well as the absolute level after pollution control impacts.

In this technique and several others, the analyst must consider the extent to which a price increase may occur to cover the pollution control expenditures. This consideration is discussed here and is not repeated in the next three technique descriptions. The determination of impact from any pollution control situation is highly sensitive to whether a plant source can increase the price of its products and therefore pass on to the consumers the costs of pollution control. To the extent that this can occur, the impact of pollution controls does not have to be absorbed by the company.

The increase of price, however, can sometimes lead to a slight reduction in total products purchased from the company. Therefore, although the revenue of the company goes up to cover the pollution control costs, it can come back down slightly if fewer products of the company are purchased. The quantitative measure of this effect of a change in quantity purchased due to a change in price is referred to as elasticity. It is typical, however, that the quantitative determination of elasticity is not available in an analysis. Therefore the impact over a range of possible price behaviors can be approximated by performing the analysis as if there were no price increase and as if there were a full price increase without any change in quantity of products sold. (The analytical tables presented later do include provisions for cases in which an elasticity figure is available.) Then the analyst must use judgment to determine where in the range the impact is likely to occur. Such a judgment can be made only if the analyst can determine at least qualitatively the possible price increase that the company would be able to set for its products. The analyst should consult economic textbooks to determine how to assess elasticity.

Performing this analysis for an existing plant requires a moderate amount of effort. Performing this analysis for a new or expanded plant requires a considerable amount of forecasting by the source, not only of profit and loss but also of equity and debt financing practices.

5.2.2 Analysis Technique 2: Computation of Return on Investment (ROI) Ratio

ROI is a measure of how efficiently the investments (assets) of a plant are being utilized and thus is a measure of profitability. It is not a direct measure of capital availability.

The ROI measure is a ratio: the numerator is net profits, and the denominator is the assets value of the plant including net working capital and the net book value of fixed assets. No single criterion is recognized for determining when the ROI ratio of a plant is significantly impacted. The analyst, therefore, may perform "before" and "after" ROI impact evaluations, taking into consideration a possible price increase.

The preferred ratio with which to compare the "after" ROI is the plant's threshold rate. By threshold is meant the plant's minimum acceptable rate of profit per each new investment. Most plants have such a threshold ROI rate, which may or may not be obtainable. The analyst should remember that the minimum threshold rate for a new investment may be higher than the average ROI for existing investments.

If the threshold rate is not obtainable, the analyst may be able to obtain the industry average ROI for comparison with the plant's "after" ROI. Sources of an industry average ROI value include trade associations, Robert Morris Associates, the Federal Trade Commission, and previous industry impact studies. The analyst must use judgment to determine how much deviation from the industry average constitutes a significant impact.

If the above two rates are not obtainable, the analyst could compare the plant ROI with the marginal cost of capital, i.e., the plant's cost of the next source of funds for its investments. Significant impact would occur when the ROI is less than the marginal cost of capital.

This technique can be applied to new or existing plants and to plants with which an agency is in deliberation or is analyzing at arm's length, i.e., predicting impact without being engaged in deliberations.

In analysis of a new plant the future financial conditions must be estimated in order to perform the ROI calculation. It will be necessary for the source to forecast at least the first 2 or 3 years of operation so that the ROI impact for more than 1 year can be viewed. This measurement requires a moderate to extensive level of effort for the agency analyst.

5.2.3 Analysis Technique 3: Computation of Discounted Cash Flow (DCF)*

The discounted cash flow technique involves looking at the future operations of a plant to determine whether it would be better for the plant owners to liquidate assets or to continue operating the plant with the pollution control equipment installed. The discounting refers to a consideration of the value of money over time. This technique is a direct measure of profitability.

The technique is applicable to analysis of new or existing plants and is more applicable to plants with which the agency is in deliberations than to those being analyzed at arm's length without benefit of the plant's financial data.

The general procedure for performing this analysis is to predict the future financial conditions of the company during the useful life of the pollution control equipment. The value of future net cash flows from the plant operations plus the future terminal value of the plant (appropriately discounted) at the end of the useful life of the pollution control equipment are computed to obtain present value.

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* Reference for this discussion and for several of the tabular formats presented later was Appendix A: Draft Guidance on Nonferrous Smelter Orders Under Section 119 of the Clean Air Act, EPA Division of Stationary Source Enforcement.

The value of future cash flows must then be compared to the present value of the plant if it were immediately liquidated. If the value of future operations is greater than the present value, the firm, according to rational decision-making theory, would purchase the pollution control equipment. If the future value is less than the present value, the plant would be liquidated and the money invested elsewhere at a greater return.

The discount rate is of particular significance to this technique. The discount rate used in this analysis is a weighted average cost of capital. Capital is defined as sources of long-term funds for the company and typically includes long-term debt, preferred stock, common stock, and earnings retained in the business. Most going concerns are already earning money at a rate greater than their cost of capital. This technique is based on the premise that when the plant earns less than what the funds cost, the plant will choose to close.

The discounted cash flow technique requires forecasts in all situations. One of the difficult aspects of forecasting is that projections of greater than 2 or 3 years are often inaccurate. In addition, because forecasts are not subject to an independent audit and because they are supplied by the company, the analyst must verify or test the reasonableness of the forecast. It is therefore appropriate for an analyst to request that the company not only make a financial forecast but also describe the physical inputs that went into it. The physical inputs consist of the amounts of raw materials, labor, and other supplies needed to manufacture the product. The analyst then must obtain (from the source or others) price factors to use with the physical inputs in deriving financial data that can be compared with those supplied by the plant.

Since forecasts are realistic only for periods up to 3 years, the analyst must extrapolate net cash flow for the remaining years to the end of the useful life of the pollution control equipment.

The analysis of discounted cash flow should be done on a "before" and "after" pollution control basis and with or without a price increase to cover the pollution control costs.

This particular method is the most highly labor-intensive of those presented. The extrapolations require a considerable amount of time, as does determination of the proper labor and cost factors for the physical inputs.

5.2.4 Analysis Technique 4: Reference to Previous Impact Studies

Often an analyst can obtain an EPA economic impact study of the entire industry of which the plant under consideration is a part. Although such a study may pertain to compliance with pollution control regulations other than the one in question, it may provide applicable information on pollution control costs and economic impacts.

Economic impact analyses have been done for New Source Performance Standards (NSPS) and NESHAPS regulations by the Economic Analysis Branch of the Office of Air Quality Planning and Standards. To date approximately two dozen such studies have been performed. These studies are available through the Economic Analysis Branch Office in Durham, North Carolina. Many additional industry impact studies relating to water pollution control regulations have been performed by the Economic Analysis Branch EPA Office of Water Programs, Washington, D.C. A state or local agency analyst may wish to contact these two branches of EPA to obtain a list of available studies.

Application of an earlier study is most straightforward when the control cost magnitudes are similar, the regulatory impact under consideration is not in addition to the regulatory impact of the other study, and the other study reaches a definitive impact decision.

If the control costs are similar in magnitude and the other study concludes that a significant impact will occur, then it is likely that such a conclusion also holds for the present situation. When the conclusion is that no significant impact will occur, the analyst must use judgment to determine how far the control costs of the other study could expand while maintaining the same conclusion. The expansionary consideration can cover circumstances where the control costs of the present situation are greater than those previously studied or when the present regulatory impact is in addition to the previous one. No clear-cut criteria can be presented here to aid the analyst in calculating the expansionary limits. The judgment depends upon the particular facts of the previous study.

To the extent that another impact study is useful for gauging the impact of the situation under consideration, the amount of resources required of an agency is minimal.

5.2.5 Analysis Technique 5: Reference to Decisions by Others

One impact of pollution control regulations to consider for a source is the availability of capital to purchase the equipment. The inability for a plant source to obtain needed financing capital is indicative of significant impact, since the plant may not be able to continue to conduct business.

For a small business as defined by the Small Business Administration (SBA), the skill of SBA can be utilized to evaluate the capital availability impact of a pollution control expenditure by having a source make application. If the financing request is rejected by the SBA, sometimes called lender of the last resort, then the source is unlikely to obtain financing by any conventional means. SBA has specific programs for pollution control expenditures; currently these programs are adequately funded.

Although no similar institution is applicable to large businesses, rejections by two or more financing sources provide a similar indication of the unavailability of financing. To attribute financing inability to the pollution control regulation in question, the analyst must know that disapproval of the financing request was caused by the impact of the regulation itself and not other factors such as improper documentation or lack of management expertise.

This technique is particularly relevant when the agency is engaged in deliberations with the source and can ask the operations to apply for financing (the debt service coverage ratio allows the analyst to estimate the availability of financing without the source having to apply). This technique can be used for both new and existing sources. It calls for a relatively low level of effort, since it enlists the skills of an existing institution set up to do this type of work.

5.2.6 Analysis Technique 6: Computation of Increase in Operating Expenses or Assets

In some multiplant situations the net income for a plant will be either extremely difficult to determine or so artificially determined that it does not represent the true profit picture of that company if it were independent. The importance of determining income is that all of the above-presented techniques require it for the analysis. Where income cannot be determined with an acceptable level of accuracy, the analyst may wish to examine the operating expenses or asset replacement value of the plant and to compare them to the magnitude of the pollution control costs as an indirect evaluation technique.

This technique is applicable to new and existing sources with which the agency is in deliberations or those being analyzed at arm's length. This technique is an indirect measure of impact because it provides no definitive indication that the increase involved would cause the plant to liquidate or that the plant could not obtain financing. As with ROI, there are no criteria for determining when an increase in cost constitutes significant recognized economic impact. A level of 30 to 40 percent (after price increase considerations) is a reasonable criterion to use when related to expenses and greater than 40 to 50 percent of the asset replacement value.

This analysis technique requires a relatively moderate level of effort.

5.2.7 Comparison of the Analysis Techniques

The six techniques are compared in the accompanying matrix according to salient characteristics. The matrix describes what each technique measures, the data required for performing the technique, the sources of such data and the relative ease of acquisition, the amount of effort required by the agency, and the limitations of the technique.

Examination of the matrix reveals several pertinent points:

- For analysis of sources at arm's length, the two most appropriate methods are use of the ROI ratio and reliance upon previous impact studies.
- The discounted cash flow technique requires the most work on the part of the agency, followed by ROI, debt service coverage, and increase in operating costs or assets.
- Forecasting is required for all analyses of new sources except those based on decisions by others and previous impact studies.
- Financing decisions by others, debt service coverage, and perhaps reliance upon previous impact studies are the techniques for directly determining capital availability.
- Discounted cash flow is the most direct measure of potential for plant closure due to low profitability, followed by the indirect measure of ROI and increase in operating costs or assets.

It is emphasized that on some occasions the agency analysts will not be able to perform an analysis, or judgments will be very difficult. These techniques will accommodate most situations, however. In the event that an analyst needs advice, he should contact EPA Division of Stationary Source Enforcement in Washington or the Economic Analysis Branch in Durham.

5.3 INFORMATION NEEDED TO PERFORM ANALYSIS TECHNIQUES

This section describes more fully the information required for performing each technique and the alternative sources for obtaining the necessary information. Sample tables performing the necessary calculations are presented for each technique.

Prior to a description of the information needed for each technique, the subject of special Federal pollution control financial assistance programs will be addressed.

In some cases the benefits of these programs need to be woven into the calculations of the various techniques.

5.3.1 Special Pollution Control Financial Assistance Programs

The Federal government operates four major Federal programs to ease the financial burden of pollution control expenditures:

- Industrial Development Bonds
- SBA Direct Compliance Loans
- SBA Lease Guarantees
- Rapid Amortization

Two of these programs are particularly important to sources that have difficulty obtaining financing for pollution control and are provided by SBA.

The other two programs reduce pollution control costs; one makes available low-cost financing to companies considered credit-worthy; the other provides for rapid recovery of portions of the pollution control costs through tax reduction provisions of the Federal corporate income tax laws.

This section will briefly describe the four programs, focusing on eligible users, benefits, and access to the program.

Where it is expected that a source would use any program, the pertinent information on interest rates and terms is provided for entry to the tables pertaining to the various analysis techniques.

Additional information on these four programs can be obtained from reference: Choosing Optimum Financial Strategies: Pollution Control Systems, JACA Corp., Environmental Research Information Center, U.S. EPA, Cincinnati, Ohio.

5.3.1.1 Industrial Development Bonds--

Industrial Development Bonds (IDB's) are a type of municipal bond with lower interest rates for the company than a corporate bond and a repayment period significantly longer than that obtainable from a bank. The reason for lower costs is that the interest is tax-free to the bond buyers, which makes them willing to accept interest rates that are two to three points lower than those on taxable corporate bonds. IDB's are issued by a public entity on behalf of an industrial source and are issued for a public purpose. Pollution control equipment is considered a public purpose and is therefore eligible for this type of financing.

The amount of an issue is usually quite large, i.e., $500,000 and greater. The reasons for such large amounts are the high fixed costs of obtaining such bonds, due to advertising expenditures, bond counsels, investment bankers, and printing. The interest savings accruing to a company from use of these bonds must therefore be of sufficient magnitude to surpass such fixed costs.

The bonds are also referred to as revenue bonds as opposed to general obligation bonds, which means that only the revenue from the company is used to repay the bonds. Therefore, the benefiting company must be credit-worthy. Also, because the bonds are often sold nationwide, the reputation of the benefiting company must be fairly high. All of these factors point to the fact that only financially healthy companies and companies with large pollution control expenditures can make use of the benefits of this financing program.

Although small companies generally are not able to benefit from this program, companies with good credit position and expenditure needs of less than $500,000 can obtain the benefits of the program in some states. This occurs when the state allows the private placement of bonds whereby the bonds are sold to a single entity, such as a bank or an insurance company. The effect of this mechanism is to lower the amount of fixed costs incurred and therefore permit pollution control expenditures in amounts of less than $500,000 to be beneficially financed by industrial development bonds.

The determination of whether a source is likely to use IDB's can be based on 1) an indication from operators of the source, 2) previous use of IDB's by the source plus an expenditure greater than $500,000, or 3) an expenditure greater than $500,000 plus a good credit or bond rating. In the latter case, if the company's rating is not readily available through Dun and Bradstreet, Moody's, or Standard & Poor's, then for simplification the analyst may assume that an IDB will not be used.

When it is likely that an IDB will be used, the values of interest rate and repayment length to be entered into Table 5-2, line 2(a) are the current municipal A-rated bond yield* and 25 years. Because the choice of an A-rating and 25 years is somewhat arbitrary, these values should not be used if the analyst knows a more exact bond rating and repayment period for the company.

5.3.1.2 SBA Direct Compliance Loans--

The SBA makes loans directly (without having a bank also put up money) to "small businesses" for pollution control expenditures. The small business must fit the numerical definition of

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* Economic Indicators, Council of Economic Advisors or Survey of Current Business, U.S. Department of Commerce.

Table 5-2. POLLUTION CONTROL COSTS

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1. Capital costs including installation $__________

2. Interest Rate (i)

   a. When anticipating impact or specific financing source cannot be determined ____10____%

   b. If IDB rate possible __________%

   c. If SBA rate possible __________%

3. Tax depreciable life (n) __________years

4. Annualized costs (capital recovery factor equation times capital costs)

   Line 1 x $\frac{i(1 + i)^n}{(1 + i)^n - 1}$ $__________

5. Average annual depreciation expense$^{(1)}$

   Line 1 x $\frac{1}{n}$ $__________

6. Average annual interest expense

   (Line 4 - Line 5) $__________

7. Annual O&M costs, including insurance, & G&A$^{(2)}$ and excluding depreciation and interest $__________

8. Average annual by-product value $__________

9. Annual control costs (Lines 4 + 7 - line 8) $__________

10. Investment tax credit (.1 x Line 1) $__________

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(1) Straight line depreciation is assumed for purposes of simplifying the calculations

(2) Assume 4% of capital costs is insurance and G&A if no other figures readily available.

small as established by SBA, face a compliance requirement that can be traced to a Federal requirement, and be unable to obtain the loan or able to obtain it only at unreasonable terms. The numerical qualification is usually in terms of number of employees, ranging between 250 and 1500 depending on the industry. By a telephone call to SBA, the analyst should obtain the specific numerical limit for the Standard Industrial Classification Code (SIC) applicable to the plant's line of business. Determination of size for SBA qualifications is based on the entire company and not on only the plant being analyzed.

This SBA program is not to be confused with SBA's traditional loan programs for businesses that often have limited funds and often only guarantee bank loans having high interest rates.

Presently, the SBA interest rate on direct compliance loans is 6-5/8 percent. Loans are allowed to 30 years, although typically they are granted for a shorter period that is reasonable for the company to repay. These loans are available for purchase of add-on pollution control equipment as well as process change equipment.

To obtain an SBA loan the company should first be refused financing by a conventional source or offered financing at unreasonable terms. The source should then determine from SBA the numerical employee limits for their SIC; if the number employed is under that limit, the source may apply. Documentation of the bank situation will be required, along with a statement by the control agency of the adequacy and necessity of the proposed control equipment. The application process can be very time-consuming and may require several exchanges of information with the SBA.

If the analyst can determine by calling SBA that the source is small, and if there is some indication that the source will have difficulty obtaining conventional financing, then the analyst should use the current SBA terms as data for entry into

Table 5-2. The current SBA interest rate (obtainable from SBA) should be entered, and the repayment life should be assumed to equal the equipment's useful life.

5.3.1.3 SBA Lease Guarantees--

Some small businesses will also be eligible for conducting a lease of pollution control equipment under terms the SBA will guarantee. In the pollution control field, a lease typically occurs with Industrial Development Bond (IDB) financing, explained above. Until this program began, small businesses could not "afford" IDB's because of the high fixed costs of obtaining them. This program therefore groups the needs of several small businesses under an IDB issue guaranteed 100 percent by SBA.

Interest rates and repayment terms are similar to those of IDB's. The eligibility criteria for this program are different from those criteria of a direct compliance loan program. A company is eligible for this program if:

> together with its affiliates, (it) is independently owned and operated, is not dominant in its field of operation, does not have assets exceeding $9 million, does not have net worth in excess of $4 million, and does not have an average net income, after Federal income taxes, for the preceding two years in excess of $400,000 (average net income to be computed without benefit of any carryover loss).*

To participate in this program the small business must first obtain the sponsorship of a bank. The bank prepares a statement of opinion that the company is credit-worthy. Then the requirements of the SBA direct compliance loan program apply, i.e., the company must obtain a certificate from the control agency that the equipment is adequate and necessary, and must complete an application.

If there is some indication that this program will be used by a source, then the interest rates and repayment period as determined under SBA's compliance loan program will provide a sufficient degree of accuracy for analysis.

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* Part 121.3-11(a), Chapter 1, Title 13.

5.3.1.4 Rapid Amortization--

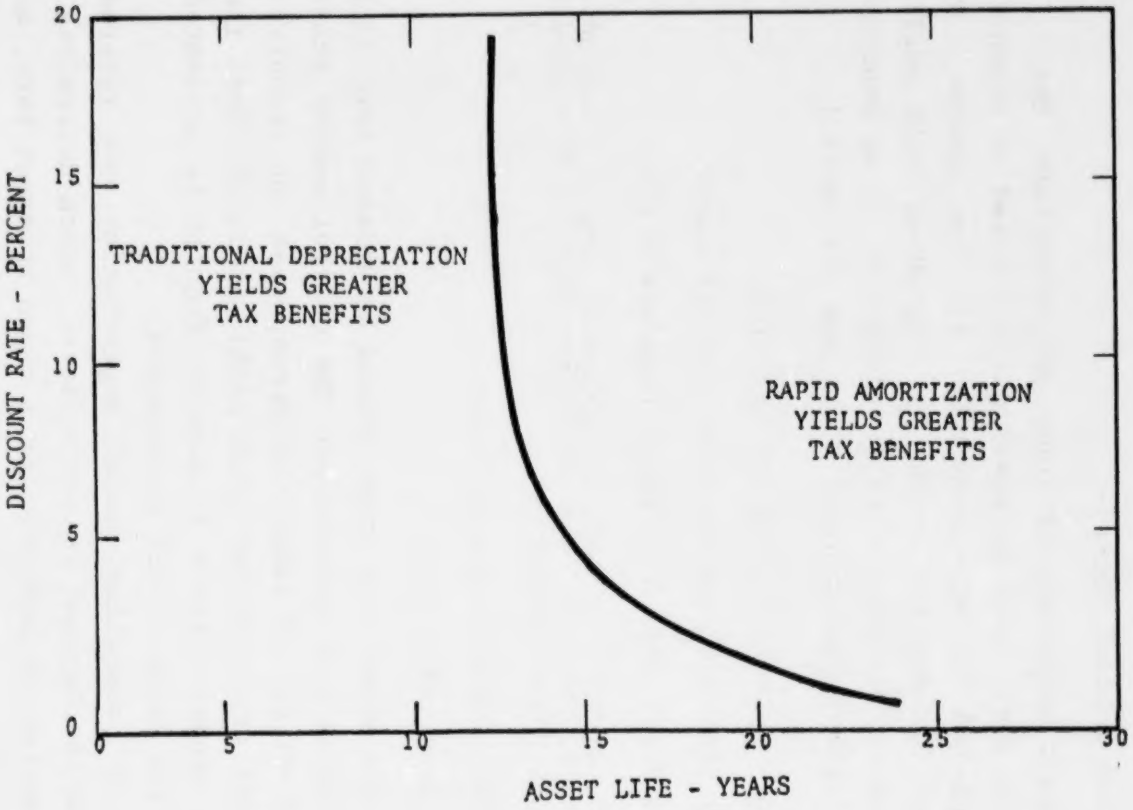
This is the only one of the four Federal programs that involves tax deductions for pollution control equipment. Although it is a special program for purchase of pollution control equipment, very few companies use it, and those that do use it do so under certain circumstances explained below.

The rapid amortization program allows expenditures for pollution control equipment to be deducted for Federal income tax purposes over a 60-month period, which is usually shorter than the normal tax-depreciable life. Along with this accelerated write-off, the source is entitled to one-half the normal 10 percent investment tax credit, or 5 percent.

To determine whether rapid amortization is beneficial, the analyst must compare, for example, using net present value (NPV) techniques, the value of 60 months' depreciation plus a 5 percent investment tax credit versus the normal tax life of the equipment and a 10 percent investment tax credit.

The results of such a comparison are presented in Figure 5-1. A company with equipment of 15 years taxable life and a 10 percent discount rate would prefer the rapid amortization, since the point at which those two figures meet on the graph is to the right of the line. If the equipment had a 10-year life and a 10 percent discount rate, however, a normal accelerated rate would be preferred. The special circumstances under which rapid amortization is preferred, then, are a relatively long (12 years or more) normal useful life of the equipment or a high discount rate coupled with equipment that has a slightly shorter useful life.

To simplify the impact analysis, it is suggested that this program not be considered as beneficial to the source. Even if the source does use rapid amortization, the difference in the



Source: Economic Analysis Division, Office of Planning and Evaluation, Environmental Protection Agency.

Figure 5-1. Indifference curve for amortization options under the Tax Reform Act of 1976 traditional vs. rapid amortization.

results will be minor. The analytical tables are formulated to reflect normal taxable useful lives of equipment and the 10 percent investment tax credit.

5.3.2 Information Required

5.3.2.1 Pollution Control Costs--

In most impact analysis techniques described here, the pollution control costs must be numerically imposed on financial information supplied by or constructed for the source. The following format for control costs, if completed, will suffice for all techniques that require this information. (As mentioned earlier, it is assumed that control costs are available.)

- Capital costs including installation
- Yearly interest rate on those capital costs
- Depreciation period in years (taxable life)
- Annual operating and maintenance costs, including insurance, general and administrative, but excluding interest and depreciation
- Byproduct recovery yearly value
- Investment tax credit

Values for the above cost items should be entered into Table 5-2 by either the source operator or the control agency staff. If the depreciation period cannot be given, then the Industrial Revenue Code asset depreciation range (ADR) can be obtained from the Federal tax manual. Since a range of figures is presented, the midpoint of the range should be selected.

The method of computing annual depreciation and interest expenses utilizes the capital recovery factor, which determines a uniform annual series of payments for a given interest rate, and life equals the initial capital expenditure.

5.3.2.2 Debt Service Coverage Ratio--

The data required to perform the debt burden coverage analysis are specified in Tables 5-2 through 5-6. Table 5-2, pollution control cost, has been discussed. Tables 5-3 and 5-4 are the profit and loss summaries for an existing and a new or expanded plant, respectively. The portion of Table 5-5 that is required for this analysis consists of lines 10 through 13; this information, to be obtained from the plant (or a suitable secondary source), consists of the future obligations, including principal, interest, lease payments, and other long-term contract obligations. Table 5-6 is the analytical table based on information from Tables 5-2 through 5-5, and is used in the coverage ratio computation.

The sources of data for Tables 5-2 through 5-6 are as follows. The data for Table 5-2 are assumed given. The data for Tables 5-3 and 5-4 should come primarily from the plant. Secondary sources of information for constructing Tables 5-3 and 5-4 can be found in other studies and references. Other studies include those previously conducted by the Environmental Protection Agency and the Occupational Safety and Health Administration. References for secondary source data would include the Robert Morris Associates, the Troy Almanac, trade associations, the Census of Manufacturers, the Federal Trade Commission, various periodicals, and equipment suppliers to the industry. When these studies and references will not provide all of the elements of Tables 5-3 and 5-4, the analyst must use judgment or ask members of industry or trade associations where to obtain the necessary data. In some cases, rough estimates may be required for such completions.

Table 5-3, the profit and loss summary for an existing plant, consists of 16 line items. The first eight are for the basic net income data prior to the impact of pollution controls. The first line calls for revenue data broken down by revenue from

Table 5-3. PROFIT AND LOSS SUMMARY FOR EXISTING PLANT

	Most Recent 5 Years				
	19	19	19	19	19
1. Revenue					
a. From operations					
b. From Non-operations					
c. Total Revenue					
2. Cost of Sales					
a. Cost of Sales					
b. Pollution control expenses (existing)(1)					
c. Total Cost of Sales					
3. Gross Operating Profits (1(c)-2(c))					
4. Depreciation & Amortization					
a. Pollution control (existing)(1)					
b. Building and improvements					
c. Transportation					
d. Machinery and equipment					
e. Other					
f. Total Depr. & Amort.					
5. Other Expenses					
a. Selling, general & administrative					
b. Taxes other than income tax					
c. Research					
d. Interest, existing obligations					
e. Bad debt allowance					
f. Long term lease payments(2)					
g. Total Expenses					
6. Net Income Before Tax (3-(4(f)+5(g))					
7. Income Taxes					
a. State					
b. Federal					
c. Total Income Taxes					
8. Net Income After Tax, Before Pollution Control 6-7(c)					

(Computations below are only performed for column of most recent year unless the source is in a cyclical business)

9. Annual Control Costs (from Table 5-2, Line 9) __________

10. Line 9 x (1-T) __________
T = (.48 if line 6 > \$50,000)
T = (.22 if line 6 < \$50,000 but < \$25,000)
T = (.20 if line 6 < \$25,000)

(continued)

Table 5-3 (continued).

11. Net Income After Tax and After Pollution Control Without Product Price Increase (Line 8 − Line 10) ________

12. Product Price Increase Under Full Recovery (Annual Control Costs ÷ Number of Units Sold per year) $________

13. % of Full Price Recovery Possible x Line 10 ________

14. Net Income After Tax, and After Pollution Control With Product Price Increase Lines 11 + 13) ________

If elasticity coefficient known and price increase expected

15.(3) Δ Profits = $Q\Delta P \times (I+E-\frac{CE}{P})$ ________

16. Net Income After Tax and After Pollution Control With Product Price Increase (Line 11 + (1-T)Line 15) ________

(1) Existing means expenses already being incurred for compliance to any air, water, solid waste, radiation, etc. pollution control regulations

(2) Greater than one year

(3) Q = Quantity Products Sold
P = Avg. Product Selling Price $= \frac{\text{Revenue Line 1 (c)}}{\text{Quantity Products Sold (Q)}}$
ΔP = increase in price (line 12)
E = elasticity coefficient
C = Unit variable costs = Lines 2+5 ÷ Q

Table 5-4. PROFIT AND LOSS SUMARY FOR NEW OR EXPANDED EXISTING PLANT

	First 3 Years of Operation (1)		
	19____	19____	19____
1. Revenue			
a) Number Units Sold	____	____	____
b) Price Per Unit	____	____	____
c) Total Revenue (2)	____	____	____
2. Cost of Sales			
a) Purchased Materials			
#____ @ ____	____	____	____
____ ____	____	____	____
____ ____	____	____	____
(use supplementary sheets for each year and for more materials if necessary)			
b) Fuel Oil Gals____ @ $____	____	____	____
c) Natural Gas cf____ @ $____	____	____	____
d) Electricity kwh____ @ $____	____	____	____
e) Labor			
Categories #hrs x Wage Rate (3)			
________ ____ ____	____	____	____
________ ____ ____	____	____	____
________ ____ ____	____	____	____
f) Total Cost of Sales	____	____	____
3. Gross Operating Profits (1(c) - 2(f))	____	____	____
4. Depreciation and Amortization			
Categories Cost Depr. Rate			
________ ____ ____	____	____	____
________ ____ ____	____	____	____
________ ____ ____	____	____	____
Total Depreciation & Amortization	____	____	____
5. Other Expenses (4)			
Category			
________	____	____	____
________	____	____	____
________	____	____	____
Total Other Expenses	____	____	____

(continued)

Table 5-4 (continued).

	First 3 Years of Operation[1]		
	19 ____	19 ____	19 ____
6. Net Income Before Taxes (3 - (4 + 5))	____	____	____
7. Income Taxes Rates: Stipulated / Avg.			
a) State ________ ____	____	____	____
b) Federal[5] ________ ____	____	____	____
c) Total Income Taxes	____	____	____
8. Net Income After Taxes (6 - 7(c))	____	____	____
9. Annual Control Costs (from Table 5-2 Line 9	____	____	____
10. Line 9 x (1 - T) T = (.48 if line 6 > \$50,000) T = (.22 if line 6 < \$50,000 but > \$25,000) T = (.20 if line 6 < \$25,000)	____	____	____
11. Net Income After Tax and After Pollution Control Without Price Increase (Line 8 - Line 10)	____	____	____
12. Product Price Increase Under Full Recovery (Annual Control Costs ÷ number units sold per year)	____	____	____
13. Percent of Full Price Recovery Possible x Line 10	____	____	____
14. Net Income After Tax and After Pollution Control With Product Price Increase (Line 11 + 13)	____	____	____
If elasticity coefficient known and price increase expected:			
15. (6) Δ Profits = $Q \Delta P \times (1 + E - \frac{CE}{P})$	____	____	____
16. Net Income After Tax and After Pollution Control With Product Price Increase (Line 11 + (1 - T) x Line 15)	____	____	____

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(1) After initial construction period.
(2) Include supplementary sheets for multi-product plant.
(3) Including benefits.
(4) If allocated then describe the basis and calculations for allocation on separate sheet.
(5) Provide separate schedule that reconciles difference between stipulated and average rate.
(6) Q = Quantity Products sold;
P = Avg. Product Selling Price = $\frac{\text{Revenue Line 1(c)}}{\text{Quantity Products Sold(Q)}}$
ΔP = Increase in Price (line 12)
E = Elasticity Coefficient
C = Unit Variable Cost = Lines (2 + 5) ÷ Q

Table 5-5. INVESTED CAPITAL SUMMARY
NEW, EXPANDED OR EXISTING PLANT

	Existing Plant (1)	New or Expanded Plant First 3 Years of Operation		
	19	19	19	19
1. Property, Plant, Equipment and Other Assets (Book Value)				
(See bottom of Table D for details)				
a. Land and minerals	____	____	____	____
b. Buildings and improvments	____	____	____	____
c. Machinery and equipment facilities	____	____	____	____
d. Pollution control (existing)	____	____	____	____
e. Transportation equipment	____	____	____	____
f. Other fixed assets (including long term marketable securities)	____	____	____	____
h. Total Book Value	____	____	____	____
2. Current Assets				
a. Cash on hand and deposit	____	____	____	____
b. Temporary cash investments	____	____	____	____
c. Trade receivables, net	____	____	____	____
d. Inventories	____	____	____	____
e. Other current assets	____	____	____	____
f. Total Current Assets	____	____	____	____
3. Current Liabilities				
a. Trade accounts payable	____	____	____	____
b. Other expense accruals	____	____	____	____
c. Notes payable, current	____	____	____	____
d. Other current liabilities	____	____	____	____
e. Total current liabilities	____	____	____	____
4. Total Net Working Capital (Line 3 minus 2)	____	____	____	____
5. Total Investment (1(h)+4) Before Controls)	____	____	____	____
6. Total Invested Capital Without Pollution Control				
a. Debt ____% $____	____	____	____	____
b. Equity (Preferred & Common Stock) ____% $____	____	____	____	____
c. Total % $____	____	____	____	____
7. Pollution Control Capital Costs, Book Value (From Table 5-2, Line 1)	____	____	____	____

(continued)

Table 5-5 (continued).

	Existing Plant(1)	New or Expanded Plant First 3 Years of Operation		
	19___	19___	19___	19___
8. Total Investment After Controls (5+7)	___	___	___	___
9. Total Invested Capital With Pollution Control				
a. Debt ____% $____	___	___	___	___
b. Equity (Preferred & Common Stock ____% $____	___	___	___	___
c. Total 100% $____	___	___	___	___

(Figures Below Required Over Life of Pollution Control Equipment)

10. Current Installments on Long Term Debt Without Pollution Control						
a. Interest	___	___	___	___	___	etc.
b. Principal	___	___	___	___	___	etc.
11. Current Installments on Pollution Control Debt						
a. Interest	___	___	___	___	___	etc.
b. Principal	___	___	___	___	___	etc.
12. Lease Payments and Long Term Contracts	___	___	___	___	___	etc.
13. Lines 10 + 11 + 12	___	___	___	___	___	etc.

List of Major Property, Plant and Equipment Items

Item	Cost	% Rate of Depreciation	Item	Cost	% Rate of Depreciation
___	___	___	___	___	___
___	___	___	___	___	___
___	___	___	___	___	___
___	___	___	___	___	___
___	___	___	___	___	___

(1) Figures for existing plant do not have to include physical descriptions of facilities if obtained from audited statements.

Table 5-6. DEBT SERVICE ANALYSIS

Numerator of Debt Service Ratio						Denominator of Debt Service Ratio					
FOR EXISTING SOURCE BEFORE POLLUTION CONTROL											
1. Net income, before taxes and interest plus 1/3 x lease payments, most recent 5 years	___	___	___	___	___	4. Principal Payments, Next 5 years ÷ (1-T)	___	___	___	___	___
						5. Interest Payments, Next 5 years	___	___	___	___	___
2. Depreciation, most recent 5 years	___	___	___	___	___	6. Lease and Long Term Contract Payments	___	___	___	___	___
						7. Capital Expenditures for Replacement, Next 5 years ÷(1-T)	___	___	___	___	___
3. Sub-total (Cash Flow From Operations)	___	___	___	___	___	8. Sub-Total	___	___	___	___	___
FOR EXISTING SOURCES AFTER POLLUTION CONTROL, WITHOUT PRICE INCREASES											
9. Pollution Control, O&M Costs (Line 7 - Line 8, Table 5-2	___	___	___	___	___	12. Pollution Control Interest Payments (Line 11(a) Table 5-5)	___	___	___	___	___
10. Pollution Control Equipment Depreciation	___	___	___	___	___	13. Pollution Control Principal Payments (Line 11(b) Table 5-5) ÷ (1-T)	___	___	___	___	___
						14. Line 12 + 13	___	___	___	___	___
11. Line 3 (above)+Line 10 Line 9	___	___	___	___	___	15. Line 8 (above) + 14	___	___	___	___	___
FOR EXISTING SOURCES AFTER POLLUTION CONTROL, WITH PRICE INCREASE											
16. Line 13 or Line 15, Table 5-3 or 5-4 x(1-T)	___	___	___	___	___						
17. Line 11 (above) + Line 16	___	___	___	___	___	18. Line 14 (above)	___	___	___	___	___

the operations of the basic business and additional revenues that are ancillary to the main business of the plant or are sporadic operations. The cost of sales category, line 2, consists of all of the costs of producing the product. The value for line 3 is the difference between lines 1 and 2. Line 4 consists of the noncash flow, depreciation, and/or amortization amounts for the various items of land, equipment, and buildings. Line 5 consists of all of the other nonproduction expenses incurred by the company, broken down into various categories as shown. Where these or any other costs are allocated from other plants or headquarters offices, the basis for the allocation should be explained and quantified. Line 6 is the net income before tax, which consists of line 3 minus lines 4 and 5. Line 7 is the income tax burden for the net income before tax and line 8 is the net income after tax but before the impact of pollution controls.

Lines 9 through 16 call for three different net income computations. The computation on lines 10 and 11 assumes that the pollution control costs are totally absorbed by the company with no product price increase and therefore that profits are decreased by the amount of the annual control costs times one minus the marginal income tax rate. The computation on lines 12 through 14 assumes that there is a price increase of a percentage, perhaps 100, of the product price increase that would be necessary to fully recover the cost of the pollution control equipment. This computation assumes that an elasticity coefficient is not available and that the analyst would use judgment as to what percent of the full product price recovery is possible. Lines 15 and 16 of Table 5-3 determine profits when an elasticity coefficient is known and when a price increase is expected.

Table 5-4 is a profit and loss summary for a new or an expanded existing plant. The line items 1 through 16 are the same as those of Table 5-3. The difference in Table 5-4 is largely in lines 1 through 7, which present the various revenue and cost items. The primary difference is that the entries in Table 5-4 require physical input data, which are then factored by costs to determine the financial result. This method can be used by itself as the sole financial forecast, or it can be used to verify any strictly financial forecast provided by the source for the various line items.

The primary source for these line item inputs is the plant source under consideration. Secondary sources of information would be the various studies and references mentioned earlier.

Table 5-5, applicable to an existing or new plant, calls for invested capital data for such plants. The lines that are necessary for the performance of the debt service coverage analysis are lines 10 through 13, explained above.

Table 5-6 is for the debt service coverage analysis, which brings together the elements of the previous tables. As explained in Section 5.2, the debt service coverage is a ratio, the numerator of which is the cash flow from operations and the denominator of which is the future debt burden. Table 5-6 is divided into three parts: the ratio before pollution control impacts, the ratio after pollution control impacts but without a price increase, and the ratio after pollution control and with a price increase.

The table is to be read as if there are two columns. The column on the left represents the numerator of the debt service coverage ratio and the column on the right, the denominator. Lines 1 through 3 of the left-hand column in the before-pollution-control situation show that the cash flow consists of the net income before taxes and interest payments plus one-third times any lease payments that might be present and depreciation. The reason for multiplying the lease payments by one-third is to approximate the interest that is part of those lease payments.

Lines 4 through 8 of Table 5-6 in the before-pollution-control situation lists the obligations, consisting of principal payments, interest payments, lease payments, other long-term contracts, and the capital expenditures necessary for replacement items. The principal and capital expenditures payments are divided by one minus the marginal tax rate in order to compute the amount of after-tax cash flow that pays for capital expenditures and principal payments. The division by one minus the marginal tax rate gives the appearance of making the principal payments larger than they actually are. The division is necessary, however, to make both sides comparable from a tax standpoint. If the left-hand part of the table could have been presented on an after-tax basis, the division would not have been necessary.

A question arises in this analysis in conjunction with the cash flow from depreciation and the capital expenditures for replacement. The question is whether the agency would wish to force the operators of source to forego replacement expenditures and use the cash flow that would have gone for these expenditures to meet the principal interest and lease payment obligations. If the agency would not like to make that assumption, then it may want to consider making the future yearly capital expenditure levels equal to the depreciation funds. The effect of this is to make lines 2 and 7 cancel each other.

The second section of Table 5-6, left hand column, computes the cash flow from operations after the occurrence of pollution control costs. This cash flow is then compared with the adjusted cash flow, right hand column, from line 8 above, which consists of adding the pollution control interest payments and the principal payments, the latter divided by 1 minus the marginal tax rate.

The next section provides a similar analysis for the impact after pollution control where a price increase does occur. The left-hand column adjusts the cash flow from operations for the additional revenue from the price increase, and the right-hand column does not adjust the payments, but has them equal to line 14 of the second part of the table.

The coverage ratios can be computed in more than one way. The analyst may wish to average the last 5 years with the next 5 years. This has the effect of dampening out any cyclical effects in operation of the source. Or, the analyst may wish to choose the funds flow from operations for the most recent year, if he considers it more representative than the previous years, and compare that level with future years.

The analyst may wish to account for inflation in adjusting the ratio. If it appears that the plant under consideration is increasing earnings on a real basis (i.e., after inflation), then the analyst may wish to adjust the cash flows of the previous years by a rate of inflation to more accurately compare past and future cash flows.

Concerning the decision criteria, if the ratio is greater than 2.0, it is considered that cash flow is adequate to cover the future obligations. A ratio of 1.5 to 2.0 indicates that the cash flow is probably adequate to cover future obligations, but that some risk is inherent. As a criterion for this technique, a numerical figure of less than 1.5 was chosen as the level below which the cash flow is not considered adequate to cover debt-burden and therefore as the level that constitutes significant impact. The benefit of performing this calculation for conditions before pollution control is that the analyst can identify those cases where a significant impact may not occur even though the ratio after pollution control is less than 1.5 but greater than 1.0. This situation would occur where the plant source is accustomed to operating at such a ratio.

The analyst also needs to determine whether the source has "unproductive" long-term assets that can be sold to finance the pollution control equipment. Such assets would appear in Table 5-5, line 1(f) (see next section for the explanation of Table 5-5).

The analyst should note that the values developed for many lines of the various tables are not entered into the final calculations in application of an analysis technique. In some cases, therefore, it is not necessary to know the breakdown of certain line items, or the analyst may wish to obtain information only for critical line items of the tables, as long as the information is highly accurate. Sometimes, the "extra" lines serve as a validation or as input for compiling values for other lines.

5.3.2.3 Return on Investment (ROI) Ratio--

Tables 5-2 through 5-5 and Table 5-7 are necessary to perform the Return on Investment (ROI) technique. Tables 5-2 through 5-4 are to be completed as described above. Lines 1 through 9 of Table 5-5 are to be completed for this analysis. These lines consist of the asset values of the plant source, to be reported at book value. The best source for these data would be other EPA or OSHA impact studies performed on the industry, plus the sources referenced earlier. Line 1 is for long-term assets; lines 2 and 3 are current assets and current liabilities, respectively. Line 4 is the difference between lines 2 and 3, which is called Net Working Capital. Line 5 is the total investment value of the plant without the pollution control expenditure under consideration. Line 5 is the sum of lines 1 and 4. Line 6 calls for a listing of the invested capital of the source divided into the debt and equity portions. (In calculation of debt amounts, deferred taxes should be treated as a debt item if it appears that in the next few years the amount of deferred taxes will decrease; otherwise they are to be treated as equity.) In addition to dividing debt and equity by their percentage contributions to the total, the absolute dollar value should also be listed as a subcategory of line 6. Line 7 is pollution control capital costs taken from Table 5-2. Line 8 is the total of assets before pollution control. The debt to equity breakdown in

Table 5-7. ROI SUMMARY FOR NEW, EXPANDED OR EXISTING PLANT

	Existing Plant 19__	Year 1,2 or 3 of Operations New or Expanded Plant 19__
1. Net Income After Taxes, Before Controls		
a. Existing (Line 8, Table 5-3)	____	xxxxxx
b. New or Expanded (Line 8, Table 5-4)	xxxxxx	____
2. Investment: Fixed Assets Plus Net Working Capital (Lines 1 + 4,Table 5-5)	____	____
3. ROI Before Controls (1 ÷ 2)	____	____
4. Total Investment with Controls (Line 2 (above) + Line 1 (Table 5-2)	____	____
5. Net Income After Taxes, After Controls Without Price Increase		
a. Existing (Line 11, Table 5-3)	____	xxxxxx
b. New (Line 11, Table 5-4)	xxxxxx	____
6. ROI After Controls Without Price Increase (5 ÷ 4)	____%	____%
7. Net Income After Controls With Price Increase		
a. Existing (Line 14 or 16, Table 5-3)	____	xxxxxx
b. New (Line 14 or 16, Table 5-4)	xxxxxx	____
8. ROI After Controls With Price Increase 7 ÷ 4)	____%	____%

percentage and dollar amounts should be presented here as a subcategory of line 9.

Table 5-7 is the analytical table for which the analysis of ROI is performed. ROI is essentially a fraction, the numerator of which is an income figure, the denominator of which is an asset figure. Table 5-7 presents the ROI before pollution control in lines 1 through 4 for existing and for new or expanded plants. Lines 5 and 6 are for computing the ROI after the occurrence of the pollution control expenditure without a price increase to cover the cost of pollution control. Lines 7 and 8 are for the ROI calculation with a price increase.

There are no established criteria for determining when the percentage change in ROI or the absolute ROI is to be considered as being significantly impacted by pollution controls. As described earlier, the analyst should first compare ROI with the plant's threshold rate of ROI for new investments. If that rate is not obtainable, the analyst should obtain an average ROI for the industry or, lastly, should obtain the firm's cost of funds for the next financing.

5.3.2.4 Discounted Cash Flow (DCF)--

To perform the Discounted Cash Flow technique, the analyst must complete Tables 5-2 through 5-4 plus Tables 5-8 and 5-9. Table 5-8 is a preliminary to the analysis conducted in Table 5-9.

The first line of Table 5-8 calls for an extrapolation of net income after tax, pollution controls, and price considerations plus interest payments over a period of years equal to the useful life of the control equipment. The analyst should use a text on extrapolation to determine which extrapolation procedure would be most applicable to the data at hand. Line 2 of Table 5-8 calls for the liquidated value of the plant. The liquidated value of a plant can be considered as the current book value of

Table 5-8. INFORMATION FOR VALUE ANALYSIS FOR NEW, EXPANDED, OR EXISTING PLANT

1. Extrapolation of Net Income After Tax After Controls, With or Without Price Increase Plus Interest Payments for Number of Years Equal to Control Equipment Life (Lines 11, 14 or 16, Tables 5-3 or 5-4 + Line 5, Table 5-3 or 5-4 ___ ___ ___ ___ ___ ___ ___ ___ ___ etc.

2. Liquidated Value
   a. New Source = 0
   b. Expanded or Existing Source = ________ (Current book value of assets (Line 1(h) + Line 4, Table 5-5) unless appraisal obtained from source.)

3. **Terminal Value** = ________ (Require source to document estimate)

4. **Cost of Equity** = 15% (I-T) or = Net Income after Controls with or without price increase (Line 11, 14 or 16, Table 5-3 or Line 11,14 or 16, Table 5-4 = ______%
   Market value of Equitey (See financial text for computation or if publicly owned company use earnings per share ÷ stock price)

5. **Weighted Average Cost of Capital (C)**

		(1)		(2)	(3)	x	(4) Cost or Interest Rate÷100	=	(5)	
Equity		______%	÷	100	______		______	Cost (From Line 4)	__________	
Debt or Preferred Stock	#1	______		100	______		______		__________	
	#2	______		100	______		______		__________	
	#3	______		100	______		______		__________	
	#n	______		100	______		______		__________	
		100%						Total	__________	= (C) Weighted Avg. Cost of Capital

Table 5-9. PRESENT VS. FUTURE VALUE ANALYSIS FOR NEW, EXPANDED, OR EXISTING PLANT

Pollution Control Equipment	**#1**	**#2**	**#3**	**#4**	**#5**	. . .	**#n**	
Depreciable Life ____ Years (n)	19	19	19	19	19	. . .	19	
1. Net Income After Tax After Controls, With or Without Price Increase Plus Interest Payments (Line 1, Table 5-8)						. . .		
2. Plus: Pollution Control Depreciation (Line 5, Table 5-2)						. . .		
Subtotal						. . .		
3. Less: Each year's current Portion of long-term debt plus leases (Line 13, Table 5-5)						. . .		
4. Less: Future new environmental Annualized Pollution Control Expenditures x (1-T) + Depr.						. . .		
5. Net Cash Flow						. . .		
6. Discount Rate $(1+C)^n$ (C is from Line 5, Column 5, Table 5-8)	$(1+C)^1$	$(1+C)^2$	$(1+C)^3$	$(1+C)^4$	$(1+C)^5$	. . .	$(1+C)^n$	Total of Line 7
7. Discounted Cash Flow (5 ÷ 6)						. . .		

8. Terminal Value ÷ $(1+C)^n$ ______
9. Investment Tax Credit (line 10, Table 5-2) ______
10. Sub-total (7+8+9) ______
11. Less Liquidated Value ______
12. Present Value ______

(1) (1+C) numbers under each line are not divisors, they are descriptive of number to be entered on line.)

the fixed assets plus the net working value, both figures being taken from Table 5-5. If the agency so desires, a source can be asked to provide its own appraisal of the liquidated value of its assets and net working capital. Such an appraisal would require documentation as to the basis for the amount provided. Line 3 of Table 5-8 is the terminal value, that is, the value of the plant at the end of the useful life of the pollution control equipment. If it is difficult for the source to estimate such a value, the analyst may wish to take the present liquidated value of the plant and increase the figure by an appropriate inflationary rate. The analyst may use discretion as to whether to use the results of the figure shown in the second part of line 4 or to use an arbitrarily high figure, such as 15 percent before tax if the plant is in financial difficulty. The arbitrary figure is based on the fact that the inherent cost of equity capital for a marginal plant is really at least 15 percent before tax in order to attract capital. Line 5 of Table 5-8 calls for calculation of the weighted average costs of capital. The capital consists of the equity cost plus the cost of the various debt or preferred-stock issues. These are to be computed on an after-tax basis. The various volumns of line 5 indicate the calculations needed to derive the weighted average costs of capital. In the event that deferred taxes are included in the capital items, the cost of such capital is to be considered zero.

Table 5-9 contains the calculations for computing the discounted cash flow technique. The period over which the calculations are to be performed is equal to the depreciable life of the pollution control equipment. The future value of the plant consists of the net income over the useful life of the pollution control equipment plus the cash flow that will be available from depreciation of the pollution control equipment. To be deducted from those amounts are the obligations of the company plus future pollution control expenditures. These pollution control expenditures are other than the one under consideration and should only be those for which the company has already entered into a contract. Additional pollution control expenditures not contracted for could be added at the discretion of the analyst if they are verifiable. The results of these calculations thus far will be a net cash flow for each of the years of the pollution control equipment's useful life. These future cash flows must be discounted to a present value by dividing each yearly figure by a compounded weighted average cost of capital, as shown in the appropriate line. The results are discounted cash flows for each year, which are summed to the right of Table 5-9. Added to these discounted cash flows are the terminal value of the plant, appropriately discounted, and the investment tax credit from the pollution control investment under consideration. To be deducted from this amount is the liquidated value of the plant as if liquidated today. If the result is greater than 0, the plant would decide to continue operations with the pollution control equipment installed. If the value is less than 0, the plant would decide, in rational decision-making theory, that greater profits are to be gained elsewhere. Thus, significant impact is considered to occur when the value is less than 0.

5.3.2.5 Previous Impact Studies--

The analyst should obtain a list of the industry economic impact studies available from EPA's Office of Water Programs and Office of Air Quality Planning and Standards. The analyst may also wish to contact OSHA for industry impact studies.

Since the sizes of the plants analyzed in such economic impact studies are likely to be different from that of the plant under consideration, it will be necessary to scale the control costs for the plants in the economic impact studies to the size of the plant being analyzed or vice versa. Scaling can be done with the aid of another EPA publication (available from the

Office of Air Quality Planning and Standards), Capital and Operating Costs of Selected Air Pollution Control Systems, EPA-450/3-76-014, May 1976.

In addition to scaling the control costs the analyst may also need to update the control costs, since some of the EPA economic impact studies may be up to 5 years old. Appropriate indices for updating those control costs are the Marshall and Swift (M&S) indices published by McGraw-Hill in Chemical Engineering.

As mentioned earlier, the analyst must use judgment to determine whether the two sets of control costs being compared justify a judgment concerning the impact of the proposed expenditures on the plant in question. There are no established criteria for the analyst to follow in making such judgment.

The earlier EPA economic impact studies will also be helpful in application of several of the other analysis techniques.

5.3.2.6 Financing Decisions by Others--

This analysis technique is applicable only to a source that is alleging difficulty in making the pollution control expenditures because of the inability to obtain financing. The technique cannot be used to anticipate the impact of air pollution control costs on a source.

First a determination of the size (number of employees) and the business Standard Industrial Classification code (SIC) of the company (not solely the plant) must be made to determine whether the source is eligible for an SBA loan. The plant is the best source for this information on number of employees and SIC. A phone call to the nearest SBA office will determine whether the company is indeed a small business. If the company is involved in more than one line of business the percent of sales for each line must be supplied to SBA.

If the business is small by SBA standards, it should be directed to apply for one of the pollution control programs of the Small Business Administration, described in Section 5.3.1. If a determination is made by the SBA that the source is refused financing solely because of the pollution control expenditure in question, then significant impact has been determined. The necessity for attributing the rejection to the pollution control expenditure is that there are many other reasons why any loan could be refused by any type of lending organization. Even without the impact the company would not have received financing; other possible reasons for refusal are lack of SBA funds, improper application documentation, management difficulties, or the inability to make a determination. The entire SBA application process may require 60 to 120 days.

If the company does not meet the SBA definition of small, it should be directed to obtain at least two letters of financing refusal from commercial financing organizations. Again, these organizations should state the refusal is attributable to pollution control costs.

This method does not adhere to the definition of "plant" given earlier because any financing organization looks to the entire company, and not just the plant, as security repayment of a loan.

5.3.2.7 Increase in Operating Expenses or Assets--

For analysis of cost increases attributable to pollution control that could lead to significant impact, the analyst must complete Tables 5-2 through 5-5, explained earlier. The cost of pollution control, i.e., annual control costs, is to be compared with lines 2, 4, and 5 of Tables 5-3 or 5-4, depending upon whether the plant is existing or new. These line items consist of plant expenses. If the annual control costs are greater than 30 to 40 percent after accounting for price increases, the significant impact may be thought to occur.

In the event that the analyst wishes to compare the fixed capital costs increase from pollution control expenditures, the first line of Table 5-2 should be compared with the first line [1(h)] of Table 5-5. The percentage increase deemed to be significant in this case is higher, i.e., 40 to 50 percent, because of the normal situation in which a new plant may have a significant portion of its cost devoted to pollution control expenditures. The figures of 30 to 40 percent for an expense increase and 40 to 50 percent for an asset increase are not based on any recognized criteria. The analyst may wish to use judgment to modify these expenditure levels.

APPENDIX A

Table A-1. CHEMICAL ENGINEERING PLANT AND EQUIPMENT COST INDEXES[a]

Index	1969 Annual	1968 Annual	1967 Annual	1966 Annual	1965 Annual	1964 Annual	1963 Annual	1962 Annual	1961 Annual	1960 Annual	1959 Annual	1958 Annual	1957 Annual
CE plant index	119.0	113.6	109.7	107.2	104.2	103.3	102.0	101.5	102.0	101.8	101.8	99.7	98.5
Engineering and supervision	110.9	108.6	107.9	106.9	105.6	104.2	103.4	102.6	101.7	101.3	102.5	99.3	98.2
Building	122.5	115.7	110.3	107.9	104.5	103.3	102.1	101.4	100.8	101.5	101.4	99.5	99.1
Construction labor	128.3	120.9	115.8	112.5	109.5	108.5	107.2	105.6	105.1	103.7	101.4	100.0	98.6
Equipment, machinery supports	116.6	111.5	107.7	105.3	102.1	101.2	100.5	100.6	100.2	101.7	101.9	99.6	98.5
Fabricated equipment	115.1	109.9	106.2	104.8	103.4	102.7	101.7	101.0	100.1	101.2	100.9	99.6	99.5
Process machinery	116.8	112.1	108.7	106.1	103.6	102.5	102.0	101.9	101.1	108.1	101.8	100.1	98.1
Pipe, valves, and fittings	123.1	117.4	113.0	109.6	103.0	101.6	100.7	100.6	101.1	104.1	103.3	98.8	97.9
Process instruments and controls	126.1	120.9	115.2	110.0	106.5	105.8	105.7	105.9	105.9	105.4	102.9	100.4	96.7
Pumps and compressors	119.6	115.2	111.3	107.7	103.4	101.0	100.1	101.1	100.8	101.7	102.5	100.0	97.5
Electric equipment and materials	92.8	91.4	90.1	86.4	84.1	85.5	87.6	89.4	92.3	95.7	101.0	100.6	98.4
Structural supports, insulation, and paint	112.6	105.7	102.1	101.0	98.8	98.3	97.3	99.2	99.8	101.9	101.6	100.4	98.0

[a] From Gard, Inc., Reference 2. More details on other cost indexes are available from this manual.

(continued)

Table A-1 (continued).

Index	1977 Annual	1976 Annual	1975 Annual	1974 Annual	1973 Annual	1972 Annual	1971 Annual	1970 Annual
CE plant index	204.1	191.1	182.3	165.4	144.1	137.2	132.3	125.7
Engineering and supervision	161.7	150.7	141.8	134.4	122.8	111.9	111.4	110.6
Building	197.2	185.3	176.9	165.5	150.6	142.0	135.5	127.2
Construction labor	176.8	172.9	168.4	163.4	157.9	152.2	146.2	137.4
Equipment, machinery supports	218.8	205.0	194.7	171.2	141.9	135.4	130.4	123.8
Fabricated equipment	212.8	198.5	192.2	170.1	142.5	136.3	130.3	122.7
Process machinery	210.1	196.9	184.7	160.3	137.6	132.1	127.1	122.9
Pipe, valves, and fittings	247.3	235.1	217.0	192.2	151.3	142.9	137.3	132.0
Process instruments and controls	201.5	192.5	181.4	164.8	147.1	143.8	139.9	132.1
Pumps and compressors	238.8	221.2	208.3	175.7	139.5	135.9	133.2	125.6
Electric equipment and materials	159.2	147.6	143.0	126.4	104.2	99.1	98.7	99.8
Structural supports, insulation, and paint	223.6	206.7	198.6	172.4	140.9	133.6	126.6	117.9

[a] From Gard, Inc., Reference 2. More details on other cost indexes are available from this manual.

Table A-2. CAPITAL RECOVERY FACTORS

Equipment life, yr	Annual compounded interest, %							
	5	6	7	8	10	12	15	20
1	1.05000	1.06000	1.07000	1.08000	1.10000	1.12000	1.15000	1.20000
2	0.53780	0.54544	0.55309	0.56077	0.57619	0.59170	0.61512	0.65455
3	0.36721	0.37311	0.38105	0.38803	0.40211	0.41635	0.43798	0.47473
4	0.28201	0.28859	0.29523	0.30192	0.31547	0.32923	0.35027	0.38629
5	0.23097	0.23740	0.24389	0.25046	0.26380	0.27741	0.29832	0.33438
6	0.19702	0.20336	0.20980	0.21632	0.22961	0.24323	0.26424	0.30071
7	0.17282	0.17914	0.18555	0.19207	0.20541	0.21912	0.24036	0.27742
8	0.15472	0.16104	0.16747	0.17401	0.18744	0.20130	0.22285	0.26061
9	0.14069	0.14702	0.15349	0.16008	0.17464	0.18768	0.20957	0.24808
10	0.12950	0.13587	0.14238	0.14903	0.16275	0.17698	0.19925	0.23852
11	0.12039	0.12679	0.13336	0.14008	0.15396	0.16842	0.19107	0.23110
12	0.11283	0.11928	0.12590	0.13270	0.14676	0.16144	0.18448	0.22526
13	0.10646	0.11296	0.11965	0.12652	0.14078	0.15568	0.22526	0.17911
14	0.10102	0.10758	0.11434	0.12130	0.13575	0.15087	0.21689	0.17469
15	0.09634	0.10296	0.10979	0.11683	0.13147	0.14682	0.17102	0.21388
16	0.09227	0.09895	0.10586	0.11298	0.12782	0.14339	0.16795	0.21144
17	0.08870	0.09544	0.10342	0.10963	0.12466	0.14046	0.16537	0.20944
18	0.08555	0.09236	0.09941	0.10670	0.12193	0.13794	0.16319	0.20781
19	0.08275	0.08962	0.09675	0.10413	0.11955	0.13576	0.16134	0.20646
20	0.08024	0.08718	0.09439	0.10185	0.11746	0.13388	0.15976	0.20536
21	0.07800	0.08500	0.09229	0.09983	0.11562	0.13224	0.15842	0.20444
22	0.07597	0.08305	0.09041	0.09803	0.11401	0.13081	0.15727	0.20369
23	0.07414	0.08128	0.08871	0.09642	0.11257	0.12956	0.15628	0.20307
24	0.07247	0.07968	0.08719	0.09498	0.11130	0.12846	0.15543	0.20255
25	0.07095	0.07823	0.08581	0.09368	0.11017	0.12750	0.15470	0.20212

(continued)

Table A-2 (continued).

Equipment life, yr	Annual compounded interest, %							
	5	6	7	8	10	12	15	20
26	0.06956	0.07690	0.08456	0.09251	0.10916	0.12665	0.15407	0.20176
27	0.06829	0.07570	0.08343	0.09145	0.10826	0.12590	0.20176	0.15353
28	0.06712	0.07459	0.08239	0.09049	0.10745	0.12524	0.20122	0.15306
29	0.06605	0.08385	0.08145	0.08962	0.10673	0.12466	0.20102	0.15265
30	0.06505	0.07265	0.08059	0.08883	0.10608	0.12414	0.20085	0.15230
31	0.06413	0.07179	0.07980	0.08811	0.10550	0.12369	0.15200	0.20070
32	0.06328	0.07100	0.07907	0.08745	0.10497	0.12328	0.15173	0.20059
33	0.06249	0.07027	0.07841	0.08685	0.10450	0.12292	0.15150	0.20049
34	0.06176	0.06960	0.07780	0.08630	0.10407	0.12260	0.15131	0.20041
35	0.06107	0.06897	0.07723	0.08580	0.10369	0.12232	0.15113	0.20034
40	0.05828	0.06646	0.07501	0.08386	0.10226	0.12130	0.15056	0.20014
45	0.05626	0.06480	0.07350	0.08259	0.10139	0.12074	0.15028	0.20005
50	0.05478	0.06344	0.08246	0.08174	0.10086	0.12042	0.15014	0.20002

Table A-3 CAPITAL COST ESTIMATION

Equipment item	Purchase price	Direct cost factor[a]	Direct cost[b]

Equipment cost[c] ______________________

Total direct cost[d] ______

A. Total direct costs ______________________

B. Total indirect costs at 38% (A)[e] ______________________

C. Contingencies at 15% (A + B) ______________________

Total capital costs (A + B + C) ______________________

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[a] From Tables 4-1, 4-2, and 4-3.

[b] Includes equipment cost and installation, instrumentation, electrical work, foundations, structural work, site work, painting, piping, and labor.

[c] Sum of equipment purchase prices.

[d] Sum of individual direct costs.

[e] Includes engineering, contractor's fee, interest during construction, shakedown, spares, freight, taxes, offsite, and field and labor expenses.

Table A-4. SUMMARY OF PREDESIGN ESTIMATE OF ANNUALIZED COSTS

Item	Unit cost	Quantity	Cost
DIRECT OPERATING COST			
I. Utilities			
Raw materials	$ /ton	tons/yr	
Electricity	$ /kWh	kWh	
Water	$ /10^3 gal	10^3 gal/yr	
Steam	$ /10^3/lb	10^3 lb/yr	
Gas	$ /10^6 Btu	10^6 Btu/yr	
Fuel oil	$ 10^3 gal	10^3 gal/yr	
II. Operating labor			
Direct labor	$ /man-hour	man-hours/h operation	
Supervision	15% direct labor		
III. Maintenance (see Tables 4-6, 4-7)			
Labor and materials			
Supplies			
Replacement parts			
IV. Sludge disposal	$ /ton	tons/yr	
V. Wastewater treatment	$ /10^3 gal	10^3 gal/yr	
FIXED COSTS			
I. Taxes, insurance, overhead, etc.	4% of total capital investment		
II. Capital recovery charges	% of total capital investment		
		TOTAL FIXED COSTS	
PRODUCT RECOVERY CREDIT	$ /ton	tons/yr	
		TOTAL ANNUALIZED COSTS	

PLANT AND PROCESS PARAMETERS

Type of process:________________________________

Production capacity, tons/h ______________________

Throughput capacity, tons/h ______________________

Annual production, tons/h ________________________

Operating time, h/yr _____________________________

Emission limitation, lb/h
gr/scf ______________________

Estimated length of ductruns, ft _________________

Space limitations:______________________________

Other limitations/restrictions: __________________

EMISSION DATA SUMMARY

Parameter	High	Variation average	Low
Gas flow rate, acfm			
Temperature, °F			
Moisture content, % V			
Grain loading, gr/scf			
Particle size distribution, % W < μm_2			
Gas analysis			
% V O_2			
% V CO_2			
% V CO			
% V SO_x			
% V N_2			
Uncontrolled emission rate, lb/h gr/scf			
Emission limitation, lb/h gr/scf			

SUMMARY OF PREDESIGN CAPITAL COST ESTIMATES

Equipment item	Design basis	Capacity/ size	Cost sources and basis	Bare cost	Installation factor	Direct installed cost

Footnotes:

A. Total direct cost
B. Total indirect cost % A
C. Contingency 20% (A+B)
Total capital cost

APPENDIX B

SAMPLE COST ESTIMATES FOR AN AIR POLLUTION CONTROL SYSTEM USING THE COST ESTIMATING PROCEDURE

DESIGN DATA FOR THE CONTROL SYSTEM

Process Parameters

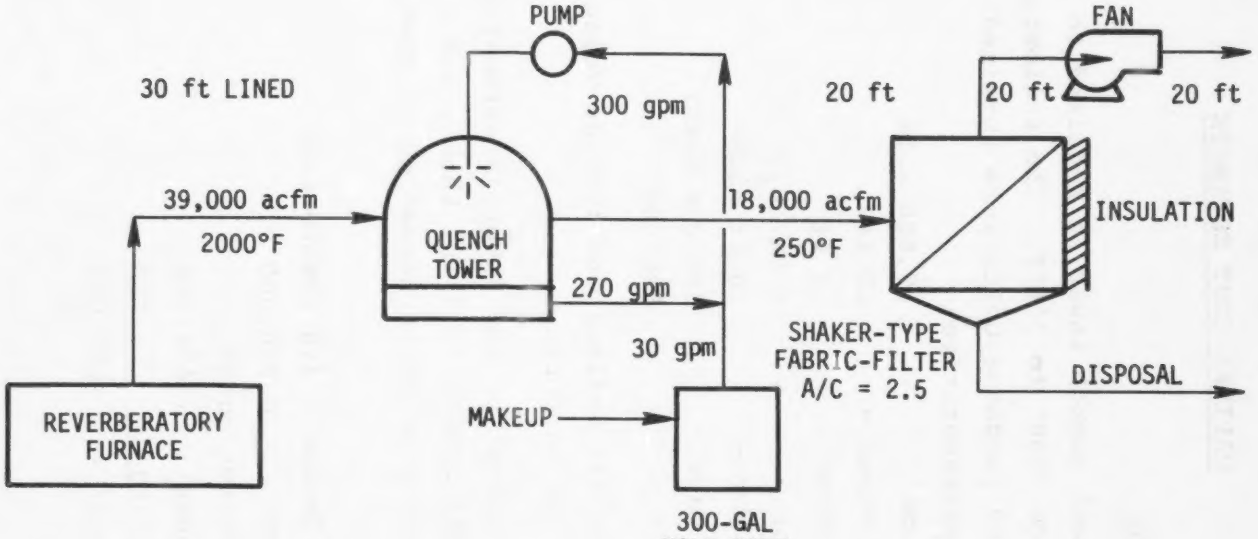
Type: Reverberatory furnace
Production capacity: 45 Mg/h (50 TPD)
Operating time: 6000 h/yr
Emission limit: 3.6 kg/h (7.9 lb/h)
Ductwork: 110 feet total
Solid waste disposal: landfill in sealed barrels

Emission Characteristics

Exhaust volume: 18.4 m^3/s (39,000 acfm)
Temperature: 1090°C (2000°F)
Emission rate: 83 kg/h (183 lb/h) particulate matter
Grain loading: 5.7 g/m^3 (2.5 gr/scf)
Particle size: Majority between 0.03 - 0.5 μm

Control System Design

Shaker-type fabric filter
Superficial velocity, 1.2 cm/s (2.5 ft/min)
System pressure drop, 1.8 kPa (7 in. H_2O)
Efficiency, greater than 99 percent
Annual labor, 2000 h


PUMP
FAN
30 ft LINED
300 gpm
20 ft
20 ft
20 ft
39,000 acfm
2000°F
QUENCH TOWER
18,000 acfm
250°F
INSULATION
270 gpm
30 gpm
SHAKER-TYPE FABRIC-FILTER A/C = 2.5
DISPOSAL
REVERBERATORY FURNACE
MAKEUP
300-GAL HOLD TANK

A/C = air-to-cloth ratio.

Figure B-1. Control system diagram for reverberatory furnace.

CAPITAL COST ESTIMATE

A. QUENCH TOWER

A carbon steel quench tower is required to cool the exhaust gases from 2000° to 250°F. The following design specifications and purchase costs were obtained from a Croll-Reynolds representative:

Exhaust volume -	39,000 acfm
Diameter of tower -	10 ft
Depth of packing -	3 ft
Pressure drop -	2 in. H_2O
Height of tower -	16 ft high
Liquid flow rate -	300 gpm water
Purchase cost -	$26,000

Prices are in mid-1977 dollars and include vessel, spray heads, controls, and supports.

Refractory lining for the tower is estimated at $50 per ft^3 installed. The lining is 4 in. thick, and a total of 220 ft^3 of refractory brick is needed at an installed cost of $11,000.

Direct cost factor = 3.0 (Table 4-2)
Purchase cost = $26,000

Total direct costs

Tower	$78,000
Lining	11,000
Total	$89,000

B. PUMP SYSTEM

A cast iron centrifugal pump capable of handling 300 gpm at 100 ft head is required for the gas cooling system. A 20-hp pump system was previously purchased from an Ingersoll-

Rand supplier in 1971 for $1000. The price included the base, couples, and motor. This application requires a 15-hp pumps system, arrived at in the following manner:

$$\text{horsepower} = \frac{(\text{gpm})\ (\text{ft head})}{3387\ (\text{efficiency})} = \frac{300\ (100)}{3387\ (0.5)}$$

$$= 15\ \text{hp}$$

The price of the 15-hp pump in 1977 is estimated as follows:

$$\text{Purchase price} = \left(\frac{15\ \text{hp}}{20\ \text{hp}}\right)^{0.52} \times \$1000 \times \frac{1.403}{0.934} = \$1300$$

The direct cost factor is 2.4 (Table 4-2).

Direct cost = 2.4 ($1300) = $3100

C. HOLD TANK

It is estimated that 30 gpm of water will be lost and must be made up on a continuous basis. A retention tank of 10-min capacity (300 gallons) is required. Carbon steel construction is adequate. A 1968 purchase price of $4270 is obtained from a technical journal. The CE indexes yield an estimated 1977 price of $6900. The direct cost factor of 2.0 is applied and results in a total direct cost of $13,800.

D. FABRIC FILTER

A shaker-type fabric filter is selected as the desired control. The exhaust gas volume at the inlet is 18,000 acfm at 250°F. Purchase costs were obtained from Fisher Klostermann for the following specifications:

Air-to-cloth ratio of 2.5
Dacron bags
7500 ft^2 cloth area
Insulation, shaker units, bags, ladder,
    supports, hopper, factory assembly
Purchase price = $22,500

Direct cost factor = 2.0 (Table 4-1)

Direct cost = \$45,000

E. FAN SYSTEM

The system pressure drop is predicted at 7 in. H_2O during normal operation. At 18,000 acfm capacity, the fan is sized at 35 hp in the following manner:

$$\text{horsepower} = \frac{(\text{acfm})\ (\text{pressure drop, in. } H_2O)}{6356\ (\text{efficiency})}$$

$$= \frac{18{,}000\ (7)}{6356\ (0.6)} = 35\ \text{hp}$$

From a compilation of fan system purchase prices, the 1977 price is estimated to be \$2600 for a motor, starter, and drive of carbon steel construction.

A direct cost factor of 2.5 is applied and results in a total direct cost of \$6500.

F. DUCTWORK

Approximately 50 ft of 1/4 in. carbon steel ductwork lined with refractory is required for the duct run from the furnace to the quench tower. Recommended velocity through the ductwork is 400 ft/min. A price of \$1.50/lb of installed carbon steel ductwork was obtained from a construction cost manual.

An additional 60 feet of ductwork is needed between the quench tower and stack.

$$A = \text{cross-sectional area, ft}^2 = \frac{39{,}000\ \text{acfm}}{4000\ \text{fpm}} = 9.75\ \text{ft}^2$$

$$D = \text{diameter, ft} = \frac{4\ A}{\pi}^{1/2} = \frac{4(9.75)}{\pi}^{1/2} = 3.52\ \text{ft}$$

A 42-in.-diameter duct of 1/4 in. carbon steel is selected. The weight is 5.5 lb/ft^2 and the length is 50 feet.

$$\text{Total surface area, ft}^2 = (\text{length})\ (\text{diameter})\ \Pi$$
$$= 50\ (42/12)\ \Pi = 550\ \text{ft}^2$$

Because the temperature in this duct run is 2000°F, a refractory lining is installed at a cost of $\$50/\text{ft}^3$. A 4-in. thickness is recommended by the supplier.

$$\text{Installed cost} = 550\ \text{ft}^2\ \left(\frac{4}{12}\ \text{ft}\right)\ \$50/\text{ft}^3 = \$9200$$

The 60-ft duct run from the quench chamber to the stack is 1/4-in. carbon steel. An exhaust volume of about 18,000 acfm is handled at a velocity of 400 fpm.

$$\text{Diameters, ft} = \frac{4\ (18{,}000)}{\Pi\ (4000)}^{1/2} = 2.5\ \text{ft}$$

$$\text{Total surface area, ft}^2 = 60\ (2.5)\ \Pi = 471\ \text{ft}^2$$

The direct costs for ductwork installation is calculated at \$1.50/lb.

$$\text{Total surface area, ft}^2 = 471 + 550 = 1021\ \text{ft}^2.$$
$$\text{Total weight, lb} = 1021\ \text{ft}^2\ (5.5\ \text{lb/ft}^2) = 5600\ \text{lb}$$

Direct cost for ductwork = 5600 (\$1.50) =	\$ 8,400
Direct cost for refractory =	9,200
Total direct cost =	\$17,600

The material portion of ductwork is \$3200.

G. INSULATION

The ductwork from the quench tower to the fabric filter and the fabric filter itself must be insulated. Mineral wool insulation 4 in. thick and an aluminum casing are needed for about 3000 ft^2 of surface area (estimated from ductwork and fabric filter dimensions). The direct costs are estimated from a construction cost manual at $\$7.50/\text{ft}^2$.

Table B-1. SUMMARY OF CAPITAL COSTS

Item	Equipment and material purchase cost	Direct cost factor	Direct cost
A. Quench tower and refractory lining	$ 26,000	3.0	$ 78,000
B. Pump system	1,300	3.5	4,550
C. Hold tank	6,900	2.0	13,800
D. Fabric filter	22,500	2.0	45,000
E. Fan system	2,600	2.5	6,500
F. Ductwork	3,200[a]	2.6	8,400
G. Insulation	8,700[a]	2.6	22,500
H. Refractory	5,100[b]	4.0	20,200
	Total direct cost (rounded)		$199,000

Total direct cost =	$199,000
Total indirect cost[c] =	75,600
Contingency[d] =	41,200
Total capital cost =	$316,000 (rounded)

---

[a] Back-calculated from an estimated direct cost factor of 2.6 to approximate purchase cost.

[b] Back-calculated from an estimated direct cost factor of 4.0. Included is refractory for ductwork and quench chamber.

[c] Estimated at 38 percent of direct cost.

[d] Estimated at 15 percent of direct and indirect cost.

Direct cost = \$7.50/ft^2 (3000 ft^2) = \$22,500.
The material portion is \$8700.

H. REFRACTORY

The refractory is \$9200 for the ductwork and \$11,000 for the quench tower. The total installed cost is \$20,200. The material portion is \$5100.

ESTIMATE OF ANNUAL COSTS

A. ELECTRICITY

Electricity is required to operate the shaker motors, fan, pump, conveyor, and lights. Total kilowatt hours are computed as follows:

Item	Horsepower	Kilowatts	MWh
Fan system	35	26	156
Pump system	15	11	66
Screw conveyor	5	4	24
Shaker motors	7	5	30
Lighting		10	30
Total			306

The price of electricity in this area is 5 cents/kWh. Therefore the total annual cost of electricity is:

306,000 kWh/yr ($0.50/kWh) = $15,300

B. WATER

Makeup water is required for the gas cooling system at the rate of 1.9 liters/s (30 gpm). The price of water in the area is 6.6 cents/m^3 ($0.25/$10^3$ gal). Therefore the total annual cost of water is:

$$1.9 \text{ liters/s} \; \frac{60(60)\text{s}}{\text{h}} \; \frac{6000 \text{ h}}{1000 \text{ liters/m}^3} \quad \$0.066/\text{m}^3 = \$2700$$

C. SOLID WASTE DISPOSAL

A total of 490 Mg/yr (540 tons/yr) of collected dust will be disposed of by landfilling in sealed barrels. This will cost $95 /Mg, including labor, shipment, barrels, and disposal charge at the landfill. Therefore the annual cost of solid waste disposal is:

490 Mg/yr ($95) = $46,600.

D. LABOR

It was estimated that about 2000 hours of labor would be required to operate the entire system. Labor costs \$10/man-hour. Therefore the annual labor cost is:

2000 h/yr (\$10/man-hour) = \$20,000.

E. MAINTENANCE

Labor and materials, including bag replacement, are estimated at 6 percent of the capital costs. An additional 15 percent of the labor and material is added to cover supplies. The total maintenance expense is:

Labor and materials 0.06 (\$316,000) = \$18,960
Supplies 0.15 (\$ 18,960) = 2,840
Total = \$21,800

F. FIXED COSTS

Annual capital charges are estimated on the basis of a 10-year equipment life and a compound annual interest rate on the capital of 10 percent. The capital recovery factory is 0.16275. Therefore the capital charges are:

0.16275 (\$316,000) = \$51,400

Property taxes, insurance, overhead, and other administrative costs amount to 4 percent of the capital investment, or 0.04 (\$316,000) = \$12,600.

SUMMARY OF ESTIMATED ANNUAL COSTS

Direct operating costs	
A. Electricity	$ 15,300
B. Water	2,700
C. Solid waste disposal	46,600
D. Labor	20,000
E. Maintenance	21,800
Total direct operating costs =	$106,000
Fixed costs	
F. Capital charges	$ 51,400
Property taxes, insurance, etc.	12,600
Total fixed costs	= $ 64,000
Direct operating	= $106,000
Fixed costs	= 64,000
Total annualized costs	= $170,000